Northern States Power Company

Cost Assignment and Allocation Manual

December 2012

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Cost Assignment and Allocation Manual

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I. INTRODUCTION

This Cost Assignment and Allocation Manual ("CAAM") was developed to specify the procedures that Northern States Power Company ("NSPM" or the "Company") follows in assigning and allocating costs among utility departments (electric and gas), among regulated services and nonregulated business activities and among jurisdictions.

NSPM was incorporated in 2000 and is an operating utility subsidiary of Xcel Energy Inc. (sometimes referred to as the "Parent"). Xcel Energy Inc. was initially established as a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), with oversight by the Securities and Exchange Commission ("SEC"). On August 8, 2005, the Energy Policy Act of 2005 was signed into law. This repealed PUHCA 1935 and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), which became effective on February 8, 2006. Responsibility for oversight of public utility holding companies was transferred from the SEC to the Federal Energy Regulatory Commission ("FERC") as a result of the Energy Policy Act of 2005.

NSPM is engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. NSPM also purchases, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSPM owns the following direct subsidiaries: United Power and Land Co., which holds real estate; and Private Fuel Storage LLC, which is involved in developing a private temporary spent nuclear fuel facility. NSPM is a wholly owned subsidiary of Xcel Energy.

As a member of a holding company system, NSPM receives administrative, management, environmental and other support services from Xcel Energy Services Inc. ("XES" or the "Service Company"), a centralized service company. The Service Company provides services to the Xcel Energy Inc. subsidiaries, at cost, pursuant to service agreements. The service agreement between NSPM and XES was submitted to, and approved by, the Minnesota Public Utilities Commission ("Minnesota Commission"). The cost allocation methodologies under which XES costs are assigned and allocated are set forth in that Minnesota Commission approved service agreement, and while those allocation methodologies are not the subject of this NSPM CAAM, they are referenced in several sections of the CAAM. Those same cost allocation methodologies were incorporated in the most recent ND electric rate case, Case Nos. PU-10-657 and PU-11-55.

The Service Company is referenced in the CAAM for the following reasons:

- The Service Company is listed as an affiliate company in the Affiliate Transaction section for the services it provides to NSPM.
- The Service Company and all other companies in the Xcel Energy Inc. holding company system of companies are included in the Corporate Organization to provide a listing of all affiliates of NSPM.

- The Service Company is also referenced in the Cost Assignment and Allocation Process section because this section covers processes that may cross multiple legal entities.

The NSPM CAAM contains the following sections:

- Introduction (Section I)
- Corporate Organization (Section II)
- Description of Services (Section III)
- Transactions with Affiliates (Section IV)
- Cost Assignment and Allocation Process (Section V)
- Allocating Workorders (Section VI)
- Utility Allocations (Section VII)
- Nonregulated Business Activity Allocations (Sections VIII)
- Jurisdictional Allocations (Section IX)
- Definitions, Abbreviations and Acronyms (Section X)

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc. is a registered holding company. The Parent directly owns four operating public utility subsidiaries that serve electric, natural gas, thermal and propane customers in eight states. These four utility subsidiaries are NSPM; Northern States Power Company, a Wisconsin corporation ("NSPW"); Public Service Company of Colorado, a Colorado corporation ("PSCo"); and Southwestern Public Service Company, a New Mexico corporation ("SPS"). Their collective service territories include portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. The Parent's regulated businesses also include WestGas InterState, Inc., an interstate natural gas pipeline company regulated by the FERC.

The Parent's nonregulated subsidiaries include Eloigne Co., which holds investments in rental housing projects that qualify for low-income housing tax credits.

The Parent owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., Xcel Energy Foundation, Xcel Energy WYCO Inc., and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy Inc., and many do business under the Xcel Energy name. See the following pages for a complete legal entity organizational listing for Xcel Energy Inc. and its subsidiaries.

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2011)

Xcel Energy Inc.
- Northern States Power Co Minnesota
  - NSP Nuclear Corporation
    - Nuclear Management Company, LLC
  - Private Fuel Storage LLC
  - United Power and Land Company
- Northern States Power Co Wisconsin
  - Chippewa and Flambeau Improvement Company
  - Clearwater Investments, Inc.
    - Plover LLC
    - Shoe Factory Holdings LLC
    - Woodsedge Eau Claire LP
  - NSP Lands, Inc.

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2011) (continued)

- Public Service Company of Colorado
    - 1480 Welton, Inc.
    - Beeman Ditch Company
    - Consolidated Extension Canal Company
    - East Boulder Ditch Company
    - Fisher Ditch Company
    - Gardeners' Mutual Ditch Company
    - Green & Clear Lakes Company
    - Hillcrest Ditch and Reservoir Company
    - Las Animas Consolidated Canal Company
    - PSR Investments, Inc.
    - United Water Company
- Southwestern Public Service Company
- WestGas InterState, Inc.
- Xcel Energy Communications Group Inc.
    - Seren Innovations, Inc. *
    - NCE Communications Inc.
- Xcel Energy Foundation
- Xcel Energy International Inc. *
    - Xcel Energy Argentina Inc. *
- Xcel Energy Markets Holdings Inc.
    - e prime, Inc. *
    - Young Gas Storage Company Ltd.
- Xcel Energy Retail Holdings, Inc.
    - Reddy Kilowatt Corporation
    - Xcel Energy Performance Contracting Inc.
- Xcel Energy Services Inc.
- Xcel Energy Ventures Inc.
    - Eloigne Company
        - Albany Countryside LP
        - Bemicil Townhouse LP
        - Central Towers LP
        - Chaska Brickstone LP
        - Colfax Prairie Homes LP
        - Cottage Court LP
        - Cottages of Vadnais Heights LP
        - Crown Ridge Apartments LP
        - Dakotah Pioneer LP
        - Driftwood Partners LP
        - East Creek LP
        - Edenvale Family Housing LP
        - Fairview Ridge LP
        - Farmington Family Housing LP
        - Farmington Townhome LP

Groveland Terrace Townhomes LP

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2011) (continued)

Hearthstone Village LP
J&D 14-93 LP
Jefferson Heights of Zumbrota LP
Lakeville Court LP
Lauring Green LP
Links Lane LP
Lyndale Avenue Townhomes LP
Mahtomeci Woodland LP
Majestic View LP
Mankato Townhomes LLP
Marsh Run of Brainerd LP
Marvin Garden LP
MDI LP #44
Moorhead Townhomes LP
Oakdale Leased Housing Associates LP
Park Rapids Townhomes LP
Plover LLC
Rochester Townhome LP
Rushford Housing LP
RWIC Credit Fund LP-1993
Safe Haven Homes, LLC
Shade Tree Apartments LP
Shakopee Boulder Ridge LP
Shenandoah Woods LP
Sioux Falls Housing Equity Fund II LP
Sioux Falls Partners LP
Sioux River LP
St. Cloud Housing LP
Stradford Flats LP
Tower Terrace LP
Wyoming LP
Wyoming LP II
Xcel Energy Wholesale Group Inc. *
Quixx Corporation *
Quixx Carolina, Inc. *
Quixx Linden, LP *
Quixxlin Corp. *
Quixx Linden LP *
Xcel Energy WYCO Inc.
WYCO Development, LLC

* Company is being classified in discontinued operations

III. DESCRIPTION OF SERVICES

OVERVIEW

The following pages provide a description of NSPM's regulated services and nonregulated business activities. Each description identifies the types of costs associated with each service or business activity, and identifies the business area or department which offers the service.

REGULATED SERVICES

ELECTRIC UTILITY

Electric – Residential

Residential electric service represents the provision of electric service to residential customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities operation and maintenance ("O&M") and depreciation costs, and administrative and general ("A&G") costs. These costs reside within the NSPM Electric Utility.

Electric – Commercial and Industrial

Commercial and industrial electric service represents the provision of electric service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Street Lighting

Street lighting electric service represents the provision of electric service to public authorities for lighting streets, highways, parks and other public places, or for traffic or other signal system service through Company-owned or customer-owned lighting equipment. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Other Sales to Public Authorities

Other sales to public authorities electric service represents the provision of electric service to public authorities under special agreements or contracts. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Resale

Resale electric service represents the provision of electric service to NSPM wholesale customers or public authorities for resale to end-user customers or to power marketers. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, or through facilities owned by third parties, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Interdepartmental

Interdepartmental electric service represents the provision of electric service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Off-System Electric Sales

NSPM sells electricity not required to serve its native load to off-system customers. Costs related to this activity can include fuel and purchased power costs. The revenues associated with these sales reside in FERC account 447, Sales for Resale-Electric. The costs related to this activity reside in FERC accounts 501, Fuel-Steam Generation; 555, Purchased Power; and 565, Transmission of Electricity by Others. In addition, the Company may allocate production O&M and transmission costs based on a percentage of overall sales relative to the type of off-system sales. These costs reside within the NSPM Electric Utility.

OTHER ELECTRIC OPERATING REVENUE

Rent from Electric Property

Rent from electric property results from the leasing of NSPM owned utility property not currently utilized for the provision of regulated services to non-affiliated third parties. Costs related to this service are primarily A&G costs associated with customer billings, as well as rental contract renewals. The revenue associated with the rentals resides in FERC account 454, Rent from Electric Property.

Interchange Agreement

The Interchange Agreement is a FERC-approved rate schedule that provides for the intercompany sharing of production and transmission costs of NSPM and NSPW. NSPM and NSPW operate an integrated production and transmission system, and the Interchange Agreement provides for the costs of that integrated system to be shared between NSPM and NSPW based upon demand and energy ratios reflecting usage by the respective companies. The costs associated with this agreement reside in FERC account 557, Other Power Supply Expenses; and FERC 566, Miscellaneous Transmission Expenses. The revenues reside in FERC account 456, Other Electric Revenues.

Joint Operating Agreement

The Joint Operating Agreement is a margin sharing agreement associated with proprietary energy trading activities. Revenues are recorded in FERC 456, Other Electric Revenues.

Miscellaneous Electric Revenue

In addition to the services detailed above, there are various activities that cannot be accounted for elsewhere, such as utility locating services, scrap metal sales, Windsource, customer connections and refuse derived fuel incentive. These revenues are recorded in FERC account 456, Other Electric Revenues.

GAS UTILITY

Gas - Residential

Residential gas service represents the provision of natural gas service to residential customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Commercial and Industrial

Commercial and industrial gas service represents the provision of natural gas service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within commercial and industrial gas services.

Rate Class	Maximum Requirements – Daily Therms	Maximum Requirements – Annual Therms
Small commercial	Less than 500	Less than 6,000
Large commercial	Less than 500	Greater than 6,000
Small demand billed commercial*	Less than 500	
Large demand billed commercial*	Greater than 500	

* Upstream demand costs are billed based on the highest one-day usage in the customer's history.

Gas – Interruptible

Interruptible gas service represents the provision of natural gas service to interruptible customers within the NSPM service territory. Interruptible service is subject to curtailment when either additional upstream pipeline or local distribution capacity is needed to ensure service to firm customers. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within interruptible gas service.

Rate Class	Maximum Requirements – Daily Therms
Small interruptible	Less than 2,000
Medium interruptible	Greater than 2,000 and less than 50,000
Large interruptible	Greater than 50,000

Gas – Large Firm Transportation

Large firm gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interruptible Transportation

Interruptible gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Negotiated Transportation

Negotiated firm and interruptible gas transportation service (bypass customers) represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interdepartmental

Interdepartmental gas service represents the provision of natural gas service or gas transportation service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the purchase and delivery of gas through NSPM owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Limited Firm

Standby gas service represents on-system back-up propane service for interruptible service customers. Costs associated with this service primarily include propane purchases and the facilities O&M. These costs reside within the NSPM Gas Utility.

Gas – Daily Balancing Service

Daily balancing gas service represents a service to transportation customers that allows them to remedy deviations between nominated and delivered gas and gas actually consumed by the transportation customer. Costs associated with this service primarily include upstream pipeline costs. These costs reside within the NSPM Gas Utility.

OTHER GAS REVENUE

Miscellaneous Gas Revenue

Various services are provided that cannot be accounted for elsewhere such as propane transportation charges and bundled sales. These revenues are recorded in FERC account 495, Other Gas Revenues.

COMMON ELECTRIC AND GAS REVENUE

Late Payments Fees/Miscellaneous Service Revenues

Revenues from the additional charges imposed because of customers failure to pay their bill by specified due date are recorded into FERC account 450, Electric Forfeited Discounts; and FERC account 487, Gas Forfeited Discounts. Miscellaneous customer related revenue, such as service connections and returned check charges, are recorded in FERC account 451, Miscellaneous Electric Service Revenue; and FERC account 488, Miscellaneous Gas Service Revenues.

CIP Incentives

The CIP Incentive is a mechanism established by an April 7, 2000 Order of the Minnesota Commission that provides utilities with an incentive to increase cost-effective utility investment in DSM (demand-side management) beyond the spending levels required by Minnesota Statute. The revenues associated with the CIP incentives are identified by unique JDE accounts and are recorded in FERC account 456, Other Electric Revenues; and FERC 495, Other Gas Revenues. We make an adjustment to remove these revenues from our cost of service study and they do not impact our revenue requirements.

ConnectSmart

NSPM provides a service for customers moving into or across the region to set up utility service and other subscription services to their homes (i.e., newspaper, local and long-distance telephone, cable TV, etc.). NSPM, through its call center, receives telephone requests for this service, and sends these requests, for a fee, to AllConnect (a third-party contractor) for the coordination of installation of services. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive, pension, and benefit costs are allocated based on labor dollars. The revenues and costs associated with this service are identified by unique JDE accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. For rate making purposes, in the event this service experiences revenues in excess of direct expenses, an adjustment is made to credit the net impact in FERC 456, Other Electric Operating Revenues, to reflect the benefit of this service to the utility customers.

Hazardous Waste Disposal

NSPM has a Hazardous Waste Consolidation facility at Chestnut Service Center in Minneapolis, Minnesota. The facility gathers hazardous waste material from power plants and service centers in both NSPM and NSPW service territories, consolidates and compacts the material, and packages it for shipment to a permanent hazardous waste disposal site. In addition, NSPM provides these services to various third-party customers.

NONREGULATED BUSINESS ACTIVITIES

The following business activities have been approved by the Minnesota Commission as nonregulated business activities. Detailed descriptions of each of the nonregulated business activities are provided in this section.

HomeSmart

NSPM offers a preventive maintenance subscription option for electric and gas appliances, as well as for HVAC equipment, and provides related repairs as part of this service. In addition, NSPM installs furnaces and air conditioners. Costs related to these activities include direct charges for labor, materials and outside services associated with the services provided. In addition, payroll taxes, lost time and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to nonregulated business activities. (Please refer to Section VIII of the CAAM for more information.) The revenues and costs associated with this service are identified by unique JDE accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations.

Customer Owned Street Lighting Maintenance

NSPM supplies maintenance services for communities that own their own street light systems. Services range from lamp replacement and cleaning to a full service maintenance package, which includes pole, fixture and underground fault repair. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique JDE accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E-002/M-92-614 for the Minnesota Commission order to treat this service as nonregulated.

Sherco Steam Sales to Liberty Paper Inc

NSPM supplies steam from the Sherburne County Generating Station to Liberty Paper, Inc. ("LPI") in order to meet LPI's thermal energy needs. The revenues and costs associated with this service are identified by unique JDE accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E002/M-93-1253 for the Minnesota Commission order to treat this service as nonregulated.

IV. TRANSACTIONS WITH AFFILIATES

OVERVIEW

NSPM directly incurs and pays for the majority of its costs, there are, however, services provided to NSPM by other affiliates within the Xcel Energy system of companies. In addition, NSPM provides a limited amount of operations, maintenance and management advisory services to its affiliates. NSPM has numerous Affiliated Interest Agreements that have been approved by the Minnesota Commission.

The sections below separately detail the nature and terms of transactions for services and asset transfers provided by NSPM to its affiliates, as well as services and asset transfers provided to NSPM by each of its affiliates. This section includes descriptions of affiliate transactions only, and does not include convenience payments. Refer to Section X for a definition of convenience payments.

As noted in the Introduction, NSPM receives administrative, management, accounting, legal, engineering, environmental and other support services from the Service Company. The Service Company provides the services to the Xcel Energy Inc. subsidiaries, at cost, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. While federal supervision over utility holding companies was transferred from the SEC to FERC in 2005, there have been no changes or updates in the XES allocation methods since 2004 and only minor changes in the service agreement to reflect transfer of oversight to the FERC. The updated service agreement between NSPM and the Service Company has been approved by the Minnesota Commission. The cost allocation methodologies under which the Service Company costs are assigned and allocated are set forth in the service agreement, and while they are not the subject of this NSPM CAAM, they are included in this section to provide as complete a picture as possible of all affiliate transactions. NSPM's affiliate transactions currently consist primarily of transactions with the Service Company for these services.

Terms of Transactions

Tariff Rate – The price charged to customers under applicable tariffs on file with federal or state regulatory commissions. Tariff rates are used for transactions with affiliates involving the provision of regulated services.

Fully Distributed Cost – The term fully distributed cost means that transactions billed include all direct and indirect costs, including overheads. Affiliate transactions billed by NSPM include labor related overheads and a working capital fee when appropriate. This method of assigning and allocating costs to these affiliate transactions ensures that the payments to or by NSPM are reasonable and have not resulted in any ratepayer subsidization. In the table below, the term, fully distributed cost, may also refer to a price established in a separate Affiliated Interest Agreement.

NSPM applies a labor related overhead to services provided by NSPM to affiliates and also applies a working capital fee on services NSPM provides to non-NSPM company affiliates. Both the labor related overhead and the working capital fees are discussed in Section VIII.

The remainder of this section is detailed by affiliate. Affiliates may be listed under the "Services Provided by NSPM to Affiliates" section and/or the "Services Provided by Affiliates to NSPM" section. The details relating to the nature, frequency and terms of the affiliate transactions are itemized for NSPM and each affiliate.

SERVICES PROVIDED BY NSPM TO AFFILIATES

Nature of Transactions	Terms
NSPW	
Operations and Maintenance – Production, decommissioning and transmission costs associated with the Interchange Agreement (FERC Docket No. ER02-808-000).	Fully distributed cost
SCADA and Gas Dispatch – Sharing of SCADA costs in accordance with Docket G-002/AI-94-831.	Fully distributed cost
Materials and Supplies – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost
Miscellaneous – Miscellaneous other charges, including labor, lease costs, lawn care, sewer, trash removal, and cash advances through PSC-Wisconsin approved borrowing agreement (Certificate of Authority and Order) and an Intercompany Note.	Fully distributed cost
PSCo	
Materials and Supplies – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – Margin sharing associated with proprietary energy trading activities.	Fully distributed cost
SPS	
Materials and Supplies – Materials and supplies, and any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost

Joint Operating Agreement – Margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – Miscellaneous other charges, including labor and associated loadings and lease costs.	Fully distributed cost

<u>Eloigne Company</u>

Miscellaneous – Miscellaneous other charges, including lease costs.	Fully distributed cost

<u>United Power and Land Company</u>

Electric – Commercial and Wholesale – Regulated electric services.	Tariff Rate

<u>Xcel Energy Inc.</u>

Miscellaneous - Miscellaneous other charges, including 401(k) match and a dividend on common stock	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM

<u>Xcel Energy Services Inc.</u>

The nature, frequency and terms of the services provided by the Service Company to NSPM are as follows:

<u>Nature of Transactions</u>	<u>Terms</u>
*Executive Management Services** – Represents charges for Xcel Energy Inc. executive management and services, including, but not limited to, officers of Xcel Energy Inc.	Fully distributed cost
*Investor Relations** – Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.	Fully distributed cost
*Internal Audit** – Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks.	Fully distributed cost
*Legal** – Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other	Fully distributed cost

legal matters.

*Claims Services** – Provides claims services related to casualty, public and company claims.	Fully distributed cost
*Corporate Communications** – Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy Inc. system. Manages and tracks all contributions made on behalf of the Xcel Energy Inc. system.	Fully distributed cost
*Employee Communications** – Develops and distributes communications to employees.	Fully distributed cost
*Corporate Strategy & Business Development** – Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements.	Fully distributed cost
*Government Affairs** – Monitors, reviews and researches government legislation.	Fully distributed cost
*Facilities & Real Estate** – Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.	Fully distributed cost
*Facilities Administrative Services** – Includes, but is not limited to, the functions of Mail Delivery, Duplicating and Records Management.	Fully distributed cost
*Supply Chain**– Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services include receiving, storing, issuing, shipping, returns and distribution of material and parts.	Fully distributed cost
*Supply Chain Special Programs** – Develops and implements special programs utilized across the company such as procurement cards, travel services and compliance with corporate minority women business expenditures program goals.	Fully distributed cost

*Human Resources ("HR")** – Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.	Fully distributed cost
*Finance & Treasury** – Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.	Fully distributed cost
*Accounting, Financial Reporting & Taxes** – Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.	Fully distributed cost
*Business Unit Accounting and Budgeting** – Provides financial analysis, budgeting and administrative support for the business units. (In addition, certain Business Unit Presidents are here rather than in the Executives service function.)	Fully distributed cost
*Payment & Reporting** – Processes payments to vendors and prepares statistical reports.	Fully distributed cost
*Receipts Processing** – Processes payments received from customers of the operating companies and affiliates.	Fully distributed cost
*Payroll** – Processes payroll including, but not limited to, time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.	Fully distributed cost
*Rates & Regulation** – Determines the operating companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.	Fully distributed cost
*Energy Supply Engineering and Environmental** – Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors	Fully distributed cost

compliance with environmental requirements. Oversees environmental clean up projects.	
*Energy Supply Business Resources** – Provides performance, specialists and analytical services to the operating companies' generation facilities.	Fully distributed cost
*Energy Markets Regulated Trading & Marketing** – Provides electric trading services to the operating companies' electric generation systems, including load management, system optimization and resource acquisition.	Fully distributed cost
*Energy Markets-Fuel Procurement** – Purchases fuel for operating companies' electric generation systems (excluding nuclear).	Fully distributed cost
*Energy Delivery Marketing** – Develops new business opportunities and markets the products and services for the Delivery Business Unit.	Fully distributed cost
*Energy Delivery Construction, Operations & Maintenance** – Constructs, maintains and operates electric and gas delivery systems.	Fully distributed cost
*Energy Delivery Engineering/Design** – Provides engineering and design services in support of capacity planning, construction, operations and material standards.	Fully distributed cost
*Marketing & Sales** – Provides marketing and sales services for the operating companies and affiliates for their electric and natural gas customers, including strategic planning, segment identification, business analysis, sales planning and customer service.	Fully distributed cost
*Customer Service** – Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections.	Fully distributed cost
*Aviation Services** – Provides aviation and travel services to employees.	Fully distributed cost
*Fleet** – Oversees the operating companies' Fleet Services.	Fully distributed cost
*Business Systems** – Provides basic information technology services such as: application management,	Fully distributed cost

voice and data network operations and management, customer support services, problem management services, security administration and systems management. In addition, Business Systems acts as a single point of contact for delivery of all technical services to Xcel Energy Inc. They partner with IBM to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace. They work collaboratively with partners and vendors to identify and co-fund opportunities that significantly benefit Xcel Energy Inc.'s business.

* Corporate Governance activities within this Service Function will be allocated using the average of the Assets Ratio including Xcel Energy Inc.'s per book assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and allocated labor hours, including overtime.

NSPW

Operations and Maintenance – Production, decommissioning and transmission costs associated with the Interchange Agreement (FERC Docket No. ER02-808-000).	Fully distributed cost
Miscellaneous – Miscellaneous other charges, including labor and associated loadings, contract labor, employee expenses, and cash advances through PSC-Wisconsin approved borrowing agreement (Certificate of Authority and Order) and an Intercompany Note.	Fully distributed cost
Materials and Supplies – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost

PSCo

Miscellaneous – Miscellaneous other charges, including labor and associated loadings, lease costs, and employee expenses.	Fully distributed cost

SPS

Miscellaneous – Miscellaneous other charges, including labor and associated loadings and lease costs.	Fully distributed cost

<u>Xcel Energy Inc.</u>

Miscellaneous – Miscellaneous other charges including contributions of capital, restricted stock units, and performance share plan.	Fully distributed cost

V. COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAAM provides an overview of the cost assignment and allocation principles of NSPM and the accounting processes within the monthly accounting close and within the JD Edwards ("JDE") general ledger system, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the nonregulated business activities of NSPM. Each major step of the accounting process is identified in the following paragraphs and will be explained in conjunction with the process flowchart on page V-18. Each major step results in costs being either directly assigned or allocated to regulated services and nonregulated business activities. The result of applying these principles is that each company, utility, jurisdiction and nonregulated business activity pays the full cost for any service provided to support their respective operations.

Many of the assignment and allocation processes occur either in the Service Company or are administered by Service Company personnel. As noted in the Introduction, the Service Company provides these services "at cost" to the Xcel Energy Inc. subsidiaries, including NSPM, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. While federal supervision over utility holding companies was transferred from the SEC to FERC in 2005, there have been no changes or updates in the XES allocation methods since 2004 and only minor changes in the service agreement to reflect transfer of oversight to the FERC. The updated service agreement between NSPM and the Service Company has been approved by the Minnesota Commission.

The processes discussed in this section are integral to the books and records of NSPM and are included to provide a comprehensive picture.

COST ASSIGNMENT AND ALLOCATION PRINCIPLES

NSPM applies the following cost assignment and allocation principles. The cost assignment and allocation approach is a fully distributed costing method as approved by the Minnesota Commission in NSPM's electric and gas rates cases (E002/GR-92-1185, G002/GR-92-1186 and G002/GR-97-1606) and the Minnesota Commission September 28, 1994 Order in Docket G, E-999/CI-90-1008.

The hierarchical cost assignment and allocation principles are:

1. Tariffed rate shall be used to value tariffed services provided.
2. Costs shall be directly assigned to either regulated or nonregulated business activities whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causation.

4. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

A significant portion of NSPM's costs are incurred directly by NSPM. These costs are directly assigned or allocated based on the above principles to utilities, jurisdictions and to nonregulated business activities. Utility allocations are described in Section VII and jurisdictional allocations are described in Section IX.

ACCOUNTING PROCESSES

The flowchart on page V-18 provides a high level overview of the various major steps in the monthly accounting close process and the various systems used to generate the books and records of NSPM. Several steps within the process have allocations imbedded in them and are therefore included to provide as much information as possible to promote an understanding of the major steps where direct assignment and allocation can occur.

FEEDER SYSTEMS (Addendum A, Flowchart Item 1)

The monthly close process initially starts with the collection of accounting information from numerous feeder systems as identified in Item 1 on the flowchart. Feeder systems gather accounting transactions on a monthly basis and 'feed,' or pass, those accounting transactions to JDE to build the monthly books and records of each utility operating company or affiliate of Xcel Energy Inc. that uses the JDE general ledger system.

There are two basic types of transactions in the feeder systems:

- The first basic group consists of individual transactions fed directly to JDE. These transactions come from the PowerPlant System ("PowerPlant"), the Indus PassPort Integrated Supply Chain/Accounts Payable System ("PassPort") and the Maximo System.

<u>PowerPlant System</u>
PowerPlant tracks all capital projects and work order expenditures for Xcel Energy Inc. utility operating companies on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, PowerPlant generates the overhead allocations and if appropriate the Allowance for Funds Used During Construction ("AFUDC"), and applies the overheads to the individual work orders. In addition, PowerPlant calculates monthly depreciation by legal entity and handles the transfer of work orders from FERC account 107, Construction Work in Progress, to FERC account 106, Completed Construction-Not Unitized, to FERC account 101, Utility Plant in Service. The transfer of non-utility costs is within FERC account 121, Non-Utility Property using sub accounts; from FERC account 12140, Non-Utility Construction Work in Progress, to FERC account 12112, Non-Utility Completed Construction-Not Unitized, to FERC account 12111, Non-Utility Plant in Service-Unitized.

<u>Indus PassPort Integrated Supply Chain/Work Management/Accounts Payable System</u>

The Supply Chain/Work Management components are used for inventory and work management processes by the Transmission, Distribution, and Nuclear business areas. This system is used to maintain inventory records by legal entity and bill materials to operation and maintenance jobs or capital jobs. In addition, the system is used as a work management tool by these business areas too. The system is also used to process and pay invoices of NSPM.

<u>Maximo System</u>

The Maximo system is an inventory and work management system used by the Energy Supply business area across the operating companies. This system is used to maintain inventory records by legal entity and bill materials to operation and maintenance jobs or capital jobs. In addition, the system is used as a work management tool by the Energy Supply business area.

- The second basic group of transactions is where costs are developed by either applying an internal billing rate to a unit of measure or by an allocation within a process, which charges costs to a legal entity, business area and regulated or nonregulated business activity. Transactions from Labor Distribution, Transportation Distribution and Information Technology are some of the major processes that fall within this category. Each of these distribution processes may have one or more internal billing rates to charge costs to internal users. Individual transactions are generated within any one of these distribution processes to charge costs to the regulated services and nonregulated business activities within an operating company or affiliate. For example, labor distribution charges can be directly assigned to the nonregulated JDE accounts for HomeSmart within NSPM and linked directly to FERC account 417.1, Expenses from Nonutility Operations.

  The following processes are described in greater detail later in this section.

  - Labor Distribution
  - Labor Overheads
  - Aviation Distribution
  - Stores/Warehouse Overhead
  - Purchasing Overhead
  - Transportation Distribution
  - Accounts Payable
  - Information Technology
  - Shared Assets Distribution
  - Facilities Distribution
  - Money Pool
  - Customer Billing

JDE GENERAL LEDGER PROCESSING (Addendum A, Flowchart Item 2)

Journal entries to record monthly transactions, such as interest accruals, amortizations, cash transactions, receivables setup, etc., are entered directly into JDE using the JDE journal entry input screens. These journal entries also include the journal entries to record overheads on nonregulated business activities (see Section VIII).

All of the transactions from the above processes are gathered together in JDE. Once all the transactions are recorded in JDE there are multiple processing steps within JDE, including Service Billings and Utility Allocations. These steps specifically affect regulated services and nonregulated business activities and are detailed separately on the following pages.

SERVICE BILLING (Addendum A, Flowchart Item 3)

The Service Billing function within JDE is the accounting process that is used primarily to bill the operating companies and affiliates for Service Company charges. The process is also used to bill charges from one operating company or affiliate to another operating company or affiliate and from one business area to another business area within the same legal entity.

The Service Billing function bills the Service Company direct charges and indirect allocations from the Service Company legal entity to the operating companies or affiliates. As discussed earlier in this document, the indirect allocation methods have been approved. All labor billed includes labor overheads. Whenever possible, costs related to the nonregulated business activities within an operating company or affiliate are directly charged to JDE accounts, which are linked directly to the 417 FERC accounts.

The Service Billing function may also include transactions billed out of the feeder systems, transactions billed between affiliates and transactions billed within an affiliate. For example, transactions billed from NSPM to PSCo for emergency work would flow through Service Billing.

CLEARING ACCOUNTS (Addendum A, Flowchart Item 4)

The clearing account process is being noted in this section of the CAAM because it uses the functionality of the allocation process within JDE to move the net of all expenditures and other clearings recorded on the income statement to the balance sheet for processes such as labor overheads.

ALLOCATING WORK ORDERS (Addendum A, Flowchart Item 5)

The Allocating Work Order functionality is a feature developed as part of JDE that is currently used by NSPM to allocate certain information technology costs that support multiple utility processes to the appropriate FERC functional accounts related to these processes. NSPM has four allocating work orders, which are described in Section VI.

UTILITY ALLOCATIONS (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated business activities whenever possible or charged as common and then allocated to the electric and gas utilities using Utility Allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are done monthly within the JDE system and are explained below. A study is performed annually, as well as for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM. These costs are then allocated among the utilities according to the allocations described in Section VII.

NONREGULATED BUSINESS ACTIVITY ALLOCATIONS (Addendum A, Flowchart Item 7)

In addition to the costs directly assigned to the nonregulated business activities from the Service Company and within the NSPM operating company, the nonregulated business activities are charged with a labor related overhead and an allocation of corporation costs. See Section VIII for additional information related to nonregulated business activities.

JURISDICTIONAL ALLOCATIONS (Addendum A, Item 8)

All costs that can be directly assigned or allocated to the electric or gas utility operations or to the nonregulated business activities are appropriately accounted for in the books and records of NSPM before jurisdictional allocations occur. A study is performed annually, and for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the jurisdictions of NSPM (Minnesota, North Dakota, and South Dakota), and these costs are allocated among the jurisdictions according to the allocations described in Section IX.

Service:	**LABOR DISTRIBUTION**
Description:	Wages and salaries of employees engaged in work on behalf of regulated services and nonregulated activities are assigned or allocated based on positive time reporting through the TIME labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-sixth of an hour or greater increments, while providing for aggregation of time when appropriate. Under this method, employees' time is reported on the basis of accounting codes related to specific operating utility companies or affiliates and/or functional services.
Provider of Service:	Service Company Operating companies or affiliates
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: All bi-weekly and semi-monthly employees' labor expenses are recorded by company personnel on time sheets and entered into various time reporting systems, all of which feed into the TIME labor distribution system. The employee submitting the time sheet is responsible for coding the JDE account numbers to charge the appropriate operating companies or affiliates, business function (e.g., capital, operations, maintenance, clearing, purchasing and/or warehousing, etc.) and regulated or nonregulated operations.

Time sheets must be completed and delivered to the employee's designated timekeeper by certain cut-off dates established by the Payroll Department. The employee's supervisor or manager is responsible for reviewing and approving all time sheets submitted, and verifying that the employee is using the correct JDE account numbers.

The TIME labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the JDE account number charged based on the hours worked. Accrual of payroll is to facilitate the recording of labor costs on a calendar month basis. This includes any reversal of the prior month's accrual. The charge of labor dollars for semi-monthly employees to JDE account numbers is based on a distribution of the monthly salary of the employee.

Service: **LABOR OVERHEADS**

Description: Employee labor overhead costs are captured in the following categories:

Benefit employees:

- Non-productive labor costs (vacation, sick, holiday, etc.)
- Pension (401k match, qualified and non-qualified pension consulting)
- Medical (active and retiree healthcare, FAS112 LTD, health and welfare, life and LTD premiums)
- Workers compensation
- Incentives (Incentives are a labor overhead for Service Company, PSCo, and SPS. Incentives for NSPM and NSPW are charged directly to FERC accounts 920 and 517).
- Payroll taxes (FICA, FUTA, SUTA)

Non-Benefit employees:

- Payroll taxes (FICA, FUTA, SUTA)

Provider of Service:	Service Company Operating companies or affiliates
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Labor overheads are allocated within a legal entity by calculating a separate loading rate for each cost category identified in the "Description" section above. For each legal entity and each category, the costs are allocated based on a single-factor formula that is comprised of total estimated costs for the category divided by total estimated productive labor costs. Legal entity specific rates for each category are entered into the TIME labor distribution system and applied to productive labor charges as appropriate for each resource type. Labor loadings applied to labor charges follow the labor charges. For example, Service Company labor overheads follow Service Company labor and NSPM labor overheads follow NSPM labor. Labor overhead rates are updated each month to ensure the actual costs are charged out. Additionally, a year-end true up is recorded to bring the overhead clearing accounts to zero for the calendar year.
Service:	**AVIATION DISTRIBUTION**
Description:	The Aviation Services department in the Service Company is responsible for managing and operating the two corporate leased aircraft used by the Xcel Energy system of companies. Costs include: pilot salaries and labor overheads, operation and maintenance costs, lease costs, hangar costs and administrative and general costs associated with managing the Aviation Services department.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: Aviation costs are billed out using the corporate governance three-factor formula based on revenues, assets and number of employees.

Any spousal use of the aircraft must be approved and is billed to the holding company.

Service: **STORES/WAREHOUSE OVERHEAD**

Description: Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools specific to business area as an overhead on materials and supplies as materials and supplies are issued/returned from a storeroom or warehouse.

In the Energy Supply business area, the inventory warehousing costs related to the Sherco and Hayden plants are direct charged to station operating and maintenance (O&M) and capital projects (when dedicated capital project support is performed).

Provider of Service: Service Company
Operating companies

User of Service: Operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: Overhead costs for inventory items, including rent, labor, supervision and adjustments, are accumulated within the Supply Chain or Energy Supply business area. These accumulated overhead costs are allocated to material issuances from the storeroom using the same account coding where the materials were originally charged. Certain allocated overhead expenses are capped at $3,500 per purchase order.

Each business area has a separate pool for each operating company and sets an overhead application rate for budgeting for the year based on projected overhead and materials activity.

During the year as actuals are recorded, the balances in the undistributed stores/warehouse clearing accounts are compared to the materials activity and historical trending and a new rate is determined.

Service: **PURCHASING OVERHEAD**

Description:	The Supply Chain organization in the Service Company has the responsibility for distributing the corporate purchasing and contract services costs to the functional area(s) of the operating companies or affiliates along with the cost of the materials and supplies ordered. Purchasing costs are made up of activities such as developing requisitions, contracts and purchase orders to procure materials and services and manage supplier relationships, negotiating complex procurement agreements/contracts for strategic supplier partnerships and service contracts, monitoring supplier performance, and managing purchase records, supplier qualification records and the supplier diversity program. The purchasing function is done in two different areas of the company. Supply Chain uses PassPort for companywide purchases and the Energy Supply business area uses Maximo for production related purchases.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and nonregulated business activities within an operating company.
Method of Allocation:	Costs are collected in clearing accounts on the Service Company and the operating companies and cleared via an overhead loading. The loading follows the accounting for certain purchases with the offset going to a contra clearing account. For PassPort and Maximo, certain purchases are loaded with the purchasing overhead loading up to a $3,500 cap. The $3,500 cap is calculated based on the value of the purchase order for purchase order payments, the total value of the contract payment authorization or the total value of the invoice for the request for payment. For PassPort, the loading is calculated and a new record is posted to the general ledger as a detail item. For Maximo, the loading is calculated once a month and shows up as a separate summary transaction on the general ledger.
Service:	**TRANSPORTATION DISTRIBUTION**
Description:	The Fleet Services department in the Service Company is responsible for managing the fleet assets owned by the operating companies. Fleet assets are vehicle units that are organized into class categories, which group together vehicles similar in nature. These classes are also grouped on vehicle features and costs of the units. For example, automobiles are classified by compact,

mid-sized or intermediate and full size. Each of these classes will have its own unique individual fixed rate to bill users.

The Transportation Distribution system bills internal functional areas of operating companies and affiliates for the cost of using vehicles or associated equipment. It distributes the operating costs related to vehicle units using usage rates based on the type of unit.

Costs included in the calculation of the monthly billing rate are: depreciation, lease costs, property taxes, material and labor costs for maintenance, fuel, labor loadings, and an overhead that includes labor, facilities, insurance, utilities, computer, phone, and office supplies.

Provider of Service: Service Company
Operating companies

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions and nonregulated business activities within an operating company.

Method of Allocation: The Transportation Distribution system bills each user for units assigned based on the monthly rates calculated by class category. Each month a validation report is reviewed to ensure all costs are billed and any invalid accounts are reviewed and corrected.

Service: **INFORMATION TECHNOLOGY**

Description: The Business Systems organization in the Service Company is responsible for managing the corporate Information Technology ("IT") assets and services of Xcel Energy. Business Systems bills out O&M and capital costs related to Xcel Energy's corporate IT equipment and services incurred internally, as well as costs incurred through external sources, primarily IBM and Dell. Costs include system O&M, desktop services, phone service, servers, infrastructure costs, software, software licensing, system design and implementation, labor and labor overheads, etc.

Provider of Service: Service Company

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions and nonregulated activities within an operating company.

Method of Allocation: IT costs are charged through several different methods.

Costs are charged directly to the operating companies, affiliates, jurisdictions or nonregulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible.

If costs can not be charged directly to an operating company, affiliate, jurisdiction or nonregulated activity, the costs are charged to a Service Company indirect allocation workorder that will assign the costs using a cost causative method to the companies benefiting from the system application or service.

For costs that can be identified as benefiting a particular service function, those services would be charged to a Service Company indirect allocation workorder using the approved allocation factor for that business area.

Service: **ACCOUNTS PAYABLE**

Description: The Payment and Reporting Department (Accounts Payable), in the Service Company, processes several types of documents for payment on behalf of the operating companies and affiliates. Accounts Payable uses PassPort and Concur to process invoice payments associated with purchase orders, contracts, requests for payment (non-purchase orders, non-contract invoices) and employee payments, including per diem charges, suggestion system award payments and employee expense reimbursements.

The charges for goods, materials and services, which post directly to the general ledger of each operating company and affiliate, differ for each type of document.

Provider of Service: Service Company

User of Service: Service Company, operating companies and affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: Within each operating company and affiliate, charges are directly assigned whenever possible. Charges may be distributed to multiple business functions or business areas based on the accounting code(s) on each document. If necessary, costs may be allocated using any surrogate measure that has a logical or observable correlation to the charges in the quantities sold, the services that caused the cost to be incurred or that benefited from the cost. The following are examples of some of the logical or observable correlations used to allocate costs contained on Accounts Payable documents:

- Quantity (units, count, etc.)
- Measurement or size (length, space, columnar inch, etc.)
- Volume (barrels, gallons, liters, etc.)
- Weight (ounce, pound, ton, etc.)
- Hours (hours of professional or contract services)
- Labor dollars (charge is in the same proportion as the labor hours of the department)
- Number of customers, meters, employees, etc.
- Revenue dollars
- Plant in service
- Square footage

Service: **SHARED ASSETS DISTRIBUTION**

Description: Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include structures and improvements, office furniture and equipment, computer and communication equipment, and some software systems that are used by employees in the performance of their jobs.

Provider of Service: Operating companies or affiliates

User of Service: Service Company, operating companies and affiliates

Method of Allocation: All shared asset costs are billed through the Service Company and either charged to a Service Company indirect workorder that will assign the costs using a cost causative method to the companies benefiting from the system application or service, or charged to the facilities clearing pool that will assign the costs following the labor of the employees housed in the particular facility.

Service: **FACILITIES DISTRIBUTION**

Description: Facilities costs, which include owned and leased buildings, operation and maintenance costs for the leased and owned buildings (unless covered by the rent or lease agreement), as well as internal administrative and general labor and non-labor costs are allocated to the functional area(s) of operating companies and other affiliates who benefit from the use of these facilities. The Property Services department is responsible for the owned and leased facility records.

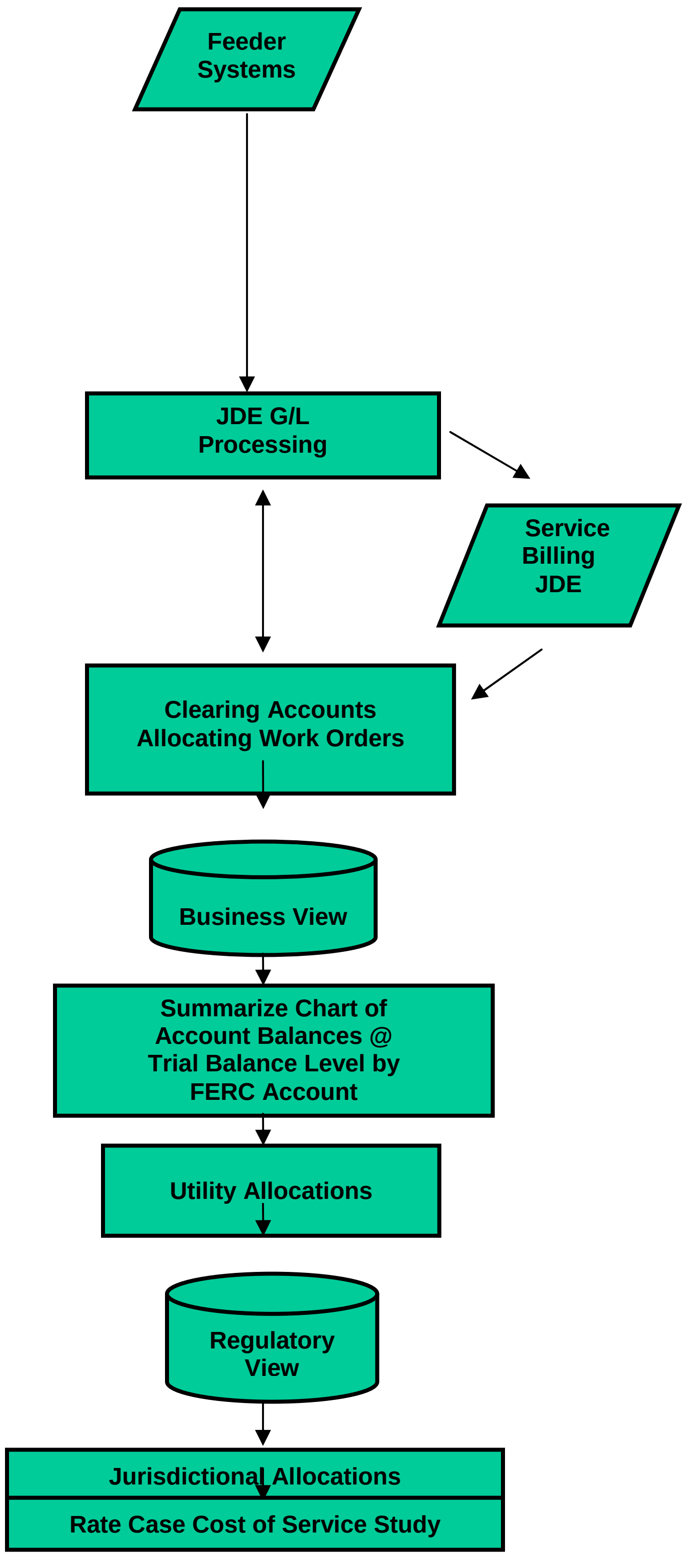
Utility owned facilities have depreciation costs with an allowed rate of return for the assets owned, the costs of which are charged directly to depreciation expense.

Provider of Service:	Service Company or operating companies
User of Service:	Service Company, operating companies and affiliates
Method of Allocation:	Costs are accumulated in the clearing account of the company benefitting from the use of the building, and are then allocated to functional FERC rent accounts based on the most recent quarter's labor charges.
Service:	**MONEY POOL**
Description:	Through the Utility Money Pool, temporary surplus funds of Xcel Energy Inc. and the operating companies are available for short-term loans to other operating companies with cash needs.
Provider of Service:	Service Company
User of Service:	Operating companies
Method of Allocation:	An operating company can borrow from, and make loans to, the Utility Money Pool, which is administered at cost by the Service Company. In addition, the holding company can deposit surplus funds into the utility money pool. The holding company can be repaid for funds deposited, but cannot borrow from the utility money pool. Interest income or expense is charged or credited, as appropriate, to the Utility Money Pool participants. All charges are directly billed to the appropriate operating company. NSPM petitioned for and received approval on the use of a utility money pool in Docket No. AI-04-100.
Service:	**CUSTOMER BILLING**
Description:	NSPM bills customers for electric, gas, propane and miscellaneous nonregulated activities through the customer billing system.
Provider of Service:	Operating companies
User of Service:	Operating companies, including utility operations, jurisdictions, and nonregulated activities.
Method of Allocation:	Costs related to customer billing are direct charged to specific operating companies whenever possible.

When costs cannot be directly assigned to a specific operating company, they are allocated based on the number of customers.

Nonregulated activities that use the customer billing system are billed for services provided based on the number of customers being billed and/or the number of phone calls which come into the call center and are then transferred to the nonregulated activity.

ADDENDUM A – PROCESS FLOWCHART



Item 1 – Feeder Systems

- PowerPlant System
- PassPort System
- Maximo System
- Labor Distribution
- Labor Overheads
- Aviation Distribution
- Stores/Warehouse Overhead
- Purchasing Overhead
- Transportation Distribution
- Information Technology
- Accounts Payable
- Shared Assets Distribution
- Facilities Distribution
- Money Pool
- Customer Billing

Item 2 – JDE General Ledger Processing

Item 3 – Service Billing

Item 4 – Clearing Accounts
Item 5 – Allocating Work Orders

Item 6 – Utility Allocations

Item 7 – Nonregulated Business Activity Allocations

Item 8 – Jurisdictional Allocations

VI. ALLOCATING WORKORDERS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated activities whenever possible. An allocating workorder is used to allocate costs to specific FERC accounts based on predefined allocation factors.

ALLOCATIONS

NSPM currently has four allocating workorders. These are as follows:

Compass/Maximo

This workorder is being used to allocate costs associated with the Business Systems' O&M costs for the Energy Supply Maximo system. These costs include information technology application, development and maintenance costs, or system support costs. The allocator is based on the number of Maximo system users. The allocator used in the current year is based on the previous years' actual number of users. The allocation was developed to distribute these costs to production FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12001	Maximo system users	Maximo system users is a reasonable methodology because the operation and maintenance costs associated with the system have a cost causative relationship with the number of users who have access to the system.

The operation and maintenance cost of the Maximo system are allocated to the following FERC accounts:

FERC account 506, Miscellaneous Steam Power Expenses
FERC account 539, Miscellaneous Hydraulic Power Generation Expenses
FERC account 549, Miscellaneous Other Power Generation Expenses

Electric Management System (EMS, also known as Electric SCADA)

This workorder is being used to allocate costs associated with Business Systems' O&M costs for the electric SCADA system. The allocator is based on the number of remote terminal units (RTUs). The allocator used in the current year is based on the previous years' actual number of RTUs. The allocation was developed to distribute these costs among production, transmission and distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection

12004	Number of RTUs	Number of RTUs is a reasonable methodology because the RTUs transmit the data used by the SCADA system.

The operation and maintenance costs of the EMS are allocated to the following FERC accounts:

FERC account 556, System Control and Load Dispatching (Production)
FERC account 561.2, Load Dispatching-Monitor/Operate Transmission System
FERC account 581, Load Dispatching (Distribution)

Gas SCADA

This workorder is being used to allocate costs associated with Business Systems' O&M costs for the gas SCADA system. The allocator is based on gas transmission and distribution plant. The allocation was developed to distribute these costs among transmission and distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12008	Gas Transmission & Distribution Plant	Gas transmission and distribution plant is a reasonable methodology because this system is used to communicate between the control rooms at the plants, transmission and distribution areas.

The operation and maintenance costs of the gas SCADA system are allocated to the following FERC accounts:

FERC account 851, System Control and Load Dispatching (Transmission)
FERC account 871, Distribution Load Dispatching (Gas)

Network Services

This workorder is being used to allocate circuit costs for service centers that primarily benefit electric and gas distribution. The allocator is based on total distribution plant. The allocation was developed to distribute these costs between electric and gas distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12011	Distribution Plant	Distribution plant is a reasonable methodology because these locations primarily benefit electric and gas distribution.

These circuit costs are allocated to the following FERC accounts:

FERC account 588, Miscellaneous Distribution Expenses (Electric)
FERC account 880, Other Expenses (Gas Distribution)

VII. UTILITY ALLOCATIONS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated activities whenever possible or charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are processed monthly within the JDE system and are explained below. The common rate base and non-O&M utility allocations are completed as part of an annual study, and also for rate case filing purposes, and are explained below.

O&M UTILITY ALLOCATIONS

Introduction

Common O&M utility allocations are applied to common costs that are recorded in A&G (FERC accounts 920-935), and customer accounting, and customer information and sales (FERC accounts 901-917). Table A in this section lists the NSPM allocation methodology applied to each FERC account or range of FERC accounts.

Methodology

NSPM uses the following methods to allocate common O&M costs. These methods were developed to achieve the most cost-causative relationship that each FERC account or range of FERC accounts has with electric and gas utility operations. The allocators used are as follows:

Customer Allocator
The customer allocator is used to allocate common utility costs in FERC accounts 901-903, and the non-commodity bad debt portion of FERC 904 and 905-917 among electric and gas operations. The allocation is based on the customer bill counts for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual customer bill count.

Revenue Allocator
The revenue allocator is used to allocate common utility costs for commodity bad debt, recorded in FERC account 904, among electric and gas operations. The allocation is based on a rolling four-year average of actual electric and gas revenues. The allocator in the current year is developed based on the four previous years' actual operating revenues from the corporate income statement.

Three-Factor Allocator
The Three-Factor Allocator is used to allocate common utility costs in FERC account ranges 920-924 and 927-935 among electric and gas utilities. The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Labor Allocator
The Labor Allocator is used to allocate common utility costs in FERC accounts 925-926 to the electric and gas departments. The allocation is based on operating labor for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual operating labor.

RATE BASE AND NON-O&M UTILITY ALLOCATIONS

Introduction

A study is performed annually, and also for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM in order to allocate them to the electric and gas utilities.

Methodology

NSPM uses the following methodology to allocate common rate base and non-O&M costs. These allocation factors were developed to achieve the most cost-causative methodology based on the pool of costs being allocated. Table B in this section lists the methodology applied to specific pools of costs. The allocators used are as follows:

Three-Factor Allocator
The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Computer Software Study
A composite allocator is used to allocate common computer software rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Software assets and related costs are presented in a cost of service study using a single amount. A study of all computer software is done to determine how each individual software asset that is part of the single amount should be allocated. All individual allocations are summarized to create a single composite allocation that is then applied to the summarized computer software plant and plant related costs.

Transportation Study
Individual allocators are used to allocate common transportation rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Transportation assets are reviewed to determine where vehicles are used and allocation factors are developed.

Table A – O&M Utility Allocations

FERC Account	Allocation Method	Basis for Allocation Selection
901-917 (excluding commodity bad debt in FERC 904)	Customer Allocator	Customer bill counts are a reasonable methodology to use to allocate common customer accounting and customer information and sales costs recorded in FERC accounts 901-917 because these costs are customer related costs, e.g., credit and collection, customer accounting, bad debt, etc.
904 (commodity bad debt portion)	Revenue Allocator	A revenue allocator is a reasonable methodology to allocate commodity bad debt because these costs have a cost-causative relationship to uncollectible utility revenues.
920-924	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.
925-926	Labor Allocator	A labor allocation is reasonable because the costs recorded in these accounts are injuries and damages and pension and benefit costs. These costs have a cost causative relationship with labor.
927-935	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.

Table B – Rate Base and Non-O&M Utility Allocations

Utility	Functional Class	Pool of Costs	Allocation Methodology
Electric			Direct Assignment
Gas			Direct Assignment
Common	26/Common Intangible Plant	Computer Software	Computer Software Study
Common	31/Common General Plant	General Furniture & Equipment	Three-Factor Allocation
Common	31/Common General Plant	Electric Distribution – Mass – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – ND	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution Vaults	Direct Assignment to Electric
Common	31/Common General Plant	Allen S King Plant	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Line – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Substation – MN	Direct Assignment to Electric
Common	31/Common General Plant	Gas Distribution – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – MN	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – ND	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – SD	Three-Factor Allocation
Common	31/Common General Plant	Software – Minnesota	Three-Factor Allocation
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – SD	Transportation Study
Common	31/Common General Plant	Prairie Island	Direct Assignment to Electric
Common	31/Common General Plant	Inver Hills – Prod Other	Direct Assignment to Electric

Common	31/Common General Plant	Big Oaks Rec Area	Three-Factor Allocation
Common	31/Common General Plant	Black Dog	Direct Assignment to Electric
Common	31/Common General Plant	High Bridge	Direct Assignment to Electric
Common	31/Common General Plant	Riverside	Direct Assignment to Electric
Common	31/Common General Plant	Sherco	Direct Assignment to Electric
Common	31/Common General Plant	Gas Prod – Wescott – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	General Plant – MN	Three-Factor Allocation
Common	31/Common General Plant	General Plant – SD	Three-Factor Allocation
Common	31/Common General Plant	General Plant – ND	Three-Factor Allocation

VIII. NONREGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

The purpose of this section is to detail the methods of assigning and allocating costs between the regulated services and the nonregulated activities of NSPM.

NSPM follows the same approach for all types of costs for its fully distributed costing method. As discussed earlier in the CAAM, NSPM's method was approved by the Minnesota Commission in its electric and gas rate cases (E002-GR-92-1185, G002-GR-92-1186 and G002/GR-97-1606) and the Minnesota Commission's September 28, 1994 Order in Docket No. G,E-999/CI-90-1008.

The Minnesota Commission established the following hierarchical cost assignment and allocation principles in Docket 1008:

1. Tariffed rate shall be used to value tariffed services provided to nonregulated activities.
2. Costs shall be directly assigned to either regulated or nonregulated activities whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogenous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causation.
4. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

This process accomplishes the proper separation of costs between NSPM's regulated utility business and nonregulated activities. Each activity that could be considered as being outside of NSPM's core electric and gas business is reviewed for regulated/nonregulated treatment. If the activity is approved to be treated as a nonregulated operation, the nonregulated cost allocation process is followed.

There are limited situations where an activity that would be in the public interest could not be pursued if a fully distributed costing approach was followed. In such circumstances, NSPM has filed, and will continue to file, any deviation from a fully distributed costing process on a project-specific basis. Any existing exceptions have been filed and approved by the Minnesota Commission.

Evaluation Process

NSPM's approach to fully distributed costing includes the following steps of analysis: business profile, direct charging, labor overheads, cost causation allocation, labor related overhead, and corporate residual allocation. Non-NSPM affiliates are charged a working capital fee as discussed in Section V.

Business Profile
The allocation process begins by reviewing each nonregulated activity for the services NSPM's utility business will be providing to the nonregulated activity.

Direct Charging (Addresses Principle #2)
Cross charges between NSPM service providers and nonregulated activities are reviewed with the business. Any process, project or service performed for the direct benefit of a nonregulated activity is directly charged to the nonregulated activity. The business area providing service to the nonregulated activity communicates the anticipated level of service and how much the service will cost.

Labor charges are directly assigned to the nonregulated activity within the budgeting process, generally based on historical charges and taking into consideration known changes. The non-labor charges are directly charged. This process enables charging for all service that will be provided.

Cost Causation Allocations (Addresses Principle #3)
If no direct charge has been established for a service expected to be provided, a cost causation allocation is developed. Direct charging is preferred. However, if a service is expected to be provided and was not budgeted as a direct charge, an estimate of the cost of the service is made and allocated to the nonregulated business. An example of this would be, when a service is being provided, but it is at such a minimal level that it would be very difficult or cost prohibitive to charge on a direct basis.

Overhead Costs (Addresses Principle #4)
The overhead allocation factors capture indirect costs associated with providing services to nonregulated activities.

NSPM currently uses a labor overhead rate developed by reviewing the expenses incurred in support of employee related activities (such as employee programs, employee relations, training, employment, compensation and benefits program development costs, diversity, safety), office equipment needs, and supervision of the service provider. The labor overhead is applied to fully loaded labor. The labor related overhead is applied to nonregulated services wholly contained within NSPM and affiliate or third party transactions.

For nonregulated services wholly contained within NSPM, a portion of NSPM's corporation costs are allocated based on a two-factor formula that takes into consideration the relative size of the nonregulated business by using number of employees and revenues.

Working Capital Fee (Addresses Principle #3)
The working capital fee is applied to non-NSPM company affiliates. The fee is based on the current Prime Rate and is reviewed and updated quarterly. This fee is to compensate the regulated business for the cost of working capital used by affiliates.

IX. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

NSPM's methods for assigning and allocating common O&M costs, plant and plant related, and other rate base investment to jurisdiction is intended to distribute costs in a manner that most closely reflects the benefit received from the expenditure. Accurately stating the assigned and allocated costs of the Company, as they relate to causation of the costs, is a fundamental part of creating a fair distribution of those costs to jurisdiction.

NSPM uses three methods to assign and allocate O&M expense, plant and plant related, and other rate base investment to jurisdiction:

1. direct assignment based on FERC account and location,
2. allocate based on cost causation, and
3. allocate based on a default allocator.

Determination of the assignment and allocation of costs to jurisdiction is an annual process designed to identify the jurisdiction(s) that receive the benefit from the cost or investment. During the review, the three methods stated above are used to ensure that the appropriate jurisdiction(s) is assigned or allocated the cost. It is NSPM's primary goal to direct assign or allocate based on cost causation as often as possible, and allocate based on a default as little as possible.

The first step in assigning costs and investments to a jurisdiction is to identify all costs that can be directly assigned to a jurisdiction (Minnesota, North Dakota or South Dakota), based on the location where work is being performed. For O&M expense, the JDE general ledger account has a location code and a FERC account number associated with it and these are used to determine the appropriate jurisdiction(s) for assigning costs. The individual business areas determine and maintain the appropriate values for these codes based on the type of work being performed and which customers benefit from it. For plant investment data, the PowerPlant system's functional class ID, state code and the function that it is serving are used to determine the appropriate jurisdictions to assign costs for plant, plant related and other rate base costs.

Direct Assignment Based on FERC Account and Location

The first method NSPM uses is to direct assign costs whenever possible. For example, the distribution portion of an electric substation (that which is assigned to a Distribution FERC account function) and is located in the Twin Cities Metro Area can be directly assigned to the State of Minnesota jurisdiction based on location as it directly serves only customers in Minnesota. In addition, all gas transmission and distribution property is directly assigned to the jurisdiction based on where the property is located as defined within the PowerPlant system. The Capital Asset Accounting organization maintains the capitalized property data.

An O&M example of direct assignment (expense) would be either electric or gas special meter reading done in the Twin Cities Metro Area (assigned to a Distribution FERC account). The meters read are for customers in the State of Minnesota; therefore, the related costs are directly assigned to Minnesota jurisdiction.

All regulatory expenses specific to a jurisdiction are directly assigned to that jurisdiction. For example, indirect assessments charged to NSPM, from the Minnesota Department of Commerce (DOC) and the Minnesota Commission, are directly assigned to the Minnesota jurisdiction.

Allocation Based on Cost Causal Relationship

The second method NSPM uses identifies all investments and costs that can be assigned to jurisdiction based on a causal relationship, and allocates these costs using the most cost causal allocation method. Examples of electric and gas analyses are as follows:

Electric
NSPM operates an integrated electric transmission system that transports electricity to NSPM's distribution system that in turn, supplies electricity to all of NSPM's customers. The transmission system is built to meet the demand created by serving its customers and, therefore, NSPM uses a coincident peak transmission demand taken from twelve consecutive months that constitute a calendar year method, to allocate transmission investment to all of its jurisdictions. All of the expense and plant investment, assigned to Transmission Function, exists to support NSPM's infrastructure, is fixed in nature and is assigned to jurisdiction based on transmission demand.

The cost causation allocators used for electric production expense or plant investment is a twelve-month coincident peak demand or energy, depending on the type of expense or plant investment. If the expense is variable in nature, energy is used to make the assignment to jurisdiction. If it is determined that the expense or plant investment exists to support NSPM's infrastructure and is fixed in nature, the demand allocator is used to make the assignment to jurisdiction.

Gas
From a supply standpoint, for example, NSPM operates its gas distribution system as a single unit. NSPM purchases natural gas, pipeline delivery capacity and transmission of gas purchased to meet its customers' requirements on a system-wide basis. In addition, NSPM also operates propane-air (LPG) peak shaving facilities and liquefied natural gas (LNG) peaking facilities to meet firm demand in excess of natural gas daily pipeline entitlement for the benefit of the entire NSPM system. Because these types of costs support the entire operating company system, it is not possible to direct assign them to a specific jurisdiction. For this example, the O&M production and storage functions are allocated to jurisdiction based on the type of expense within the FERC account number. The transmission function is allocated based on the Gas Load Dispatch allocator that is a combination of the design day firm demand allocator and total annual throughput. For plant investment, all production and storage facilities are allocated based on the gas design day allocator related to the design day firm demand.

Electric & Gas
Cost and investment in support of NSPM's Distribution, Customer Accounting, and Customer Information & Sales are more easily identified by state based on the location or where the work is being performed, or they can be allocated to jurisdiction using customers as a basis. NSPM has service territory that borders on North Dakota and South Dakota.

In cases where services are provided and serve all regional customers, a regional allocator is developed which reflects the number of customers served in Minnesota and North Dakota or Minnesota and South Dakota, depending on the region. This represents a causal relationship between costs incurred in those regions and the assignment of costs to jurisdiction. Locating services performed in the Fargo area is an example of these types of costs. Locating services are performed for customers on both sides of the border and are, therefore allocated to jurisdiction based on the number of year-end average customers in the North Dakota Region, which includes Fargo, Moorhead, Grand Forks, East Grand Forks and Minot.

Allocation Based on a Default Allocator

Allocation of common and general investment or A&G expense: Costs and investment that can not be assigned to jurisdiction using either direct assignment or allocation based on cost causation as described above are allocated to jurisdiction using a default allocator.

Common and General Plant Investment
The default allocator for electric plant investment is determined by the function that it serves. Common and general plant that serves production uses a twelve-month coincident peak demand allocator to allocate costs to jurisdiction. Plant serving transmission uses a twelve-month coincident peak transmission demand allocator to allocate costs to jurisdiction. For plant serving distribution, the number of year-end average customers is used to allocate costs to jurisdiction.

For Gas plant a default allocator is also determined by the function that it serves. For general and common plant, a year-end average customer allocator is used as the default. If the investment function has been determined to be gas production related, then the default jurisdictional allocator used in the production allocator is gas design day.

Administrative and General Expenses
When assigning or allocating A&G expenses to jurisdiction, the business area associated with the JDE general ledger account is an additional piece of information used in determining the jurisdiction(s) benefiting from the expenditure. A&G costs for business areas that support the electric production portion of the business, Energy Supply and Nuclear Generation, are allocated to jurisdiction using the twelve-month coincident peak demand allocator. Any Distribution business area A&G costs that cannot be directly assigned to jurisdictions based on the location code are allocated to jurisdiction using the twelve-month end-of-year average customer allocator.

Electric A&G costs for the remaining business areas that support a corporate function are allocated to jurisdiction using a equally weighted two-factor allocator based on electric plant in service and electric O&M expense (excluding A&G). The two factor allocator is developed by first calculating a three part historical ratio of plant investment directly serving production, transmission or distribution and a three part historical ratio of O&M expenses assigned to FERC accounts that are either production, transmission or directly serve customers (distribution, customer accounting, customer information or sales). These two ratios are then averaged to develop an equally weighted production, transmission and distribution ratio. This resulting three part ratio is then multiplied times the jurisdictional O&M default allocation ratios. The electric production portion is allocated to jurisdiction using a twelve-month coincident peak demand allocator; the transmission portion using the transmission demand allocator; and the customer portion is allocated using twelve-month end-of-year customers. The final step is to add the three sets of jurisdictional ratios together to form the two factor jurisdictional allocator used to allocate electric A&G costs supporting corporate functions.

Gas A&G expenses are allocated to jurisdiction using the appropriate customer allocation as a default allocator, based on the JDE account location code.

A more detailed description of each allocation type and method of allocation, including examples of why the allocation was chosen to assign costs to jurisdiction is included below.

Table C in this section lists the methodology applied to specific pools of costs.

ALLOCATION METHODS

GAS & ELECTRIC

<u>Allocation</u>: Direct Assigned
This allocation type is used to assign all expenses that are determined to be directly assignable to a jurisdiction (Minnesota, North Dakota, South Dakota, or Wholesale).

<u>Allocation</u>: Direct Assigned: State of Minnesota
This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the State of Minnesota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to one of Minnesota's regulatory bodies, Legal Department expense budgeted in support of Minnesota, economic development activities in the Twin Cities metro area, facilities expenses in support of the Distribution business unit in Twin Cities metro area, delivery system operation and maintenance costs in the Metro Area, Northwest and Southeast Regions and Automated Energy System (AES) expenses.

<u>Allocation</u>: Direct Assigned: State of North Dakota
This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the State of North Dakota jurisdiction. The types of costs direct assigned include: regulatory development activities based out of the North Dakota regional offices, direct and indirect assessments related to the North Dakota regulatory bodies, Law Department expenses budgeted in support of North Dakota, economic development activities performed directly for North Dakota and work performed in the Minot area for the sole benefit of North Dakota customers.

<u>Allocation</u>: Direct Assigned: State of South Dakota
This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the State of South Dakota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to the South Dakota regulatory bodies, Law Department expenses budgeted in support of South Dakota, economic development activities performed directly for South Dakota.

<u>Allocation</u>: Direct Assigned: Wholesale
This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the wholesale full requirements jurisdiction. The types of costs direct assigned include: customer billing expenses budgeted in support of wholesale customers and labor and related expenses in support of wholesale customer metering,

<u>Allocation</u>: Customers - Year-End Average - (Electric or Gas)
This allocation type is used to assign expenses where there is a cost causative relationship between the number of electric and gas utility NSP customers in a particular area and the service provided. This allocator is based on year-end average customer by utility.

<u>Allocation</u>: Customers Year-End Average
Minnesota Co. MN/ND/SD

This allocation type is used to assign costs to all of Minnesota Company's jurisdictions (Minnesota, North Dakota, South Dakota, and Wholesale) when the work performed benefits all of the company's customers equally. This is the default allocator that is used for the Electric and Gas Distribution, Customer Accounting, Customer Information, Sales and Administrative & General FERC accounts where the general ledger account JDE Business Unit Category Code 6 (Location code) designates support of NSPM Company.

This is also the Gas Utility A&G Corporate Function default allocator type.

<u>Allocation</u>: Customers Year End Average
Minnesota/North Dakota

This allocation type is used to assign costs to both the North Dakota and Minnesota jurisdictions based on customers in the entire North Dakota Region. This includes customers in Fargo, Moorhead, Grand Forks, East Grand Forks and Minot service areas. This method is the default allocator for O&M expenses associated with general ledger accounts where the JDE business unit category Code 6 (Location code) designates support for Minnesota/North Dakota.

<u>Allocation</u>: Customers Year End Average
Minnesota/South Dakota

This allocation type is used to assign costs to both the South Dakota and Minnesota jurisdictions based on customers in the entire South Dakota Region. This method is the default allocator for O&M expenses associated with general ledger accounts where the JDE Business Unit Category Code 6 (Location code) designates support for Minnesota/South Dakota.

<u>Allocation</u>: Study Jurisdictional Budget Transmission

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of Transmission. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

<u>Allocation</u>: Study for Distribution Plant Serving Wholesale

This study is used for distribution substations that are also serving wholesale customers to insure an appropriate amount goes to that jurisdiction.

<u>Allocation</u>: Study Jurisdictional Budget Distribution

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of Distribution. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

ELECTRIC UTILITY ONLY

Allocation: Energy

Fuel and fuel-related items are assigned to jurisdiction based on the energy allocator because of the direct correlation of customer sales and the level of fuel consumed. These items include all fuel; purchased energy, interchange agreement energy and variable production expenses.

Allocation: DemandProd (Coincident Peak)

The 12 coincident peak (CP) demand production allocator is used to assign fixed capacity related expenses, plant and plant related items to jurisdiction. Other expenses allocated to jurisdiction based on demand include: fixed production expenses, purchased power demand expense, interchange agreement demand charges and regulatory expenses not directly related to one of NSPM's jurisdictions. Also, any A&G costs that are directly in support of production are allocated using this method.

Allocation: DemandTran (Coincident Peak)

The 12 CP demand transmission allocator is used to assign Transmission FERC Accounts in support of NSPM's jurisdictions. Also, any A&G costs that are directly in support of transmission are allocated using this method.

Allocation: Two-Factor Allocator (A&G Only)

Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G). The Two Factor allocator is used to allocate electric A&G costs when there is not a direct or cost causative method available. Generally, all corporate electric A&G costs are allocated using this method.

GAS UTILITY ONLY

Allocation: Retail Revenues Cost of Gas Recovery - Demand, Commodity and Purchased Gas Adjustment True-up Study

Retail revenues include components for the recovery of costs associated with product and delivery of product to the service area. Such costs include capacity or entitlement costs, pipeline transportation costs, commodity costs and costs of alternative gas (propane-air or liquefied natural gas) supplied during times of firm peak demand. Regulations provide for the automatic adjustment of billing rates for price changes and the annual true up of the cost of gas incurred. Demand, Commodity and Purchased Gas Adjustment are components of the Retail Revenues Cost of Gas Recovery study. The portion of total Minnesota Company Cost of Gas included in Retail Revenues that the Minnesota jurisdiction represents is also applied to total Minnesota Company Cost of Gas expense accounts to achieve revenue neutrality for revenue requirements consideration.

<u>Allocation</u>: Design Demand Day
Expressed as a percentage, Design Demand Day is the ratio of the Minnesota jurisdiction firm peak demand volume to the total Minnesota Company firm peak demand volume that could occur on the distribution system on a day considered to be the most severe weather conditions that can be experienced.

<u>Allocation</u>: Load Dispatch
Expressed as a percentage, Load Dispatch is a combination of the Minnesota jurisdiction Design Demand Day and the Minnesota jurisdiction total Retail sales and Transportation throughput each weighted equally.

<u>Allocation</u>: Limited Firm and Standby Services Study
Expressed as a percentage, Limited Firm and Standby services, in revenues, is the ratio of Minnesota jurisdiction availability charges and volumetric charges to the total Minnesota Company; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total Minnesota Company program product costs.

Table C

Allocation to Jurisdiction							
Selection Criteria *							
Sub-Business Unit (CC2)	Plant Function	Functional Class ID / Description	Location (CC6)	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	2 /Electric Nuclear Production Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Production	Production	23 / Decommissioning	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Production	Production	23 / Decommissioning	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Production	23 / Decommissioning	Wisconsin		Electric	WI	Direct Assigned - Wisconsin
Electric Transmission	Transmission	5 / Electric Transmission Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Transmission	5 / Transmission Direct Assignment	Minnesota	DRCT	Electric	MN	Direct Assigned – State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Transmission	5 / Transmission Generation Step-up		BSLD, PEAK	Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
Sub-Business Unit (CC2)	**Plant Function**	**Functional Class ID / Description**	**Location (CC6)**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/ SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Distribution	6 / Electric Distribution Plant	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Distribution	6 / Electric Distribution Plant	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	Wholesale		Electric	WHSL	Direct Assigned - Wholesale Full Requirements
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/ SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/ SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/ SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/ SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/ SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/ SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Gas	Production	7 / Gas Manufactured Production Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Storage	9 / Gas Underground Storage Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Transmission	10 / Gas Transmission Plant			Gas	MN	Direct Assigned – State Of Minnesota
Gas	Transmission	10 / Gas Transmission Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Distribution	11 / Gas Distribution Plant			Gas	MN	Direct Assigned – State of Minnesota
Gas	Distribution	11 / Gas Distribution Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Gas - Design Demand Day

Selection Criteria *							
Sub-Business Unit (CC2)	**Plant Function**	**Functional Class ID / Description**	**Location (CC6)**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	34 / Gas Other Storage Plant			Gas	MN/ND	Gas - Design Demand Day

* All items under the Selection Criteria must be met before this allocation takes place.

X. DEFINITIONS

Abbreviations or Acronyms

The following abbreviations or acronyms are used within the CAAM document:

A&G	Administrative and General
AFUDC	Allowance for Funds Used During Construction
CAAM	Cost Assignment and Allocation Manual
Company	Northern States Power Co., a Minnesota Corporation
FERC	Federal Energy Regulatory Commission
Fleet Services	Xcel Energy Services Inc. Fleet Services Department
Holding Company	Xcel Energy Inc.
HR	Human Resources
JDE	J.D. Edwards Financial System
LPI	Liberty Paper, Inc.
Minnesota Commission	Minnesota Public Utilities Commission
NSPM	Northern States Power Co., a Minnesota Corporation
NSPW	Northern States Power Co., a Wisconsin Corporation
O&M	Operations and Maintenance
OES	Office of Energy Securities
Parent	Xcel Energy Inc.
PassPort	Indus PassPort Integrated Supply Chain/Accounts Payable System
PowerPlant	PowerPlant System
PSCo	Public Service Company of Colorado, a Colorado Corporation
PUHCA	Public Utility Holding Company Act of 1935
SCADA	Supervisory Control and Data Acquisition
Service Company	Xcel Energy Services Inc.
SEC	Securities and Exchange Commission
SPS	Southwestern Public Service Company, a New Mexico Corporation
XES	Xcel Energy Services Inc.

Terms

The following terms are used within the CAAM document:

Accounts Payable	The Payment and Reporting Department of Xcel Energy Services Inc.
Administrative and General	Includes activity in FERC accounts 920-935, Administrative and General Expenses.
Affiliate Transaction	A transfer of a good, service or asset from the utility to a non-regulated division, subsidiary or affiliate, or from a non-regulated division, subsidiary or affiliate to the utility.
Allocated	To distribute a joint or common cost to more than one affiliate, utility operation, jurisdiction or non-regulated business activity. For example, labor of an employee who works for more than one affiliate, shall be allocated based on positive time reporting or other allocation method as identified in the CAAM. Similarly, non-labor joint or common costs such as vehicles, advertising, space, etc. are subject to the cost allocation principles.
Convenience Payments	Payments made by an operating company or the Service Company on behalf of another operating company or affiliate. Convenience payments are recorded in the intercompany accounts of the company. Convenience payments are not the result of the

	Operating Company or the Service Company providing a service (a good, product or service) to an operating company or affiliate.
Cost Allocation	The method(s) used to allocate a joint or common cost.
Cost Assignment	The method or process of directly assigning a cost.
Customer Accounting Costs	Includes activity in FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910, Customer Service and Informational Expenses; and FERC accounts 911-917, Sales Expenses.
Fully Distributed Cost	Transactions billed include all direct and indirect costs, including overheads.
Operations and Maintenance	Includes activity in FERC accounts 500-935 with the exception of FERC account 501, Fuel; FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910; Customer Service and Informational Expenses; FERC accounts 911-917, Sales Expenses and FERC accounts 920-935, Administrative and General Expenses.
Supply Chain	The Supply Chain Department of the Service Company.
Service Function	A specific function of an Organizational Area. Examples include but not limited to: Executive Management, Internal Audit, Payroll and Marketing and Sales.
Subledger	A JDE Business Unit code or Work Order that designates who the charge is being billed to. A subledger is assigned to only one company or legal entity.
Tariff Rate	The price charged to customers under applicable tariffs on file with federal or state regulatory commissions. Tariff rates are used for transactions with affiliates involving the provision of regulated services.
Work Order	Accumulates costs, either for Capital, Expense or to be further allocated.

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Case No.:	PU-12-813		
Response To:	North Dakota Public Service Commission	Data Request No.	NDPSC-1-019
Requestor:	Michael Diller & Sara Cardwell		
Date Received:	February 26, 2013		

Question:

On Page 6 of the testimony of Amy Stitt in the MN General Rate Case, Docket No. 12-961, it states: "Beginning each February, the Financial Council reviews the current forecast, and establishes budget guidelines for the new five-year O&M and Capital budgets. Business areas then review their current five-year forecast and re-evaluate spending priorities. This requires them to gather detailed information on budget assumptions, create work papers that support the new assumptions, and perform detailed and comprehensive analyses." Please provide this information for the 2013 budget process completed in 2012 as well as the guidelines that will apply to the 2014 budgeting process that presumably have been completed. Also include a description of the differences in the guidelines for the 2014 budget guidelines and the reasons for those changes.

Response:

The 2013-2017 Corporate Budget Instructions are provided as Attachment A to this response. The budget instructions include the schedule and describe the guiding principles used to establish the corporate O&M and capital budgets.

The 2014-2018 Corporate Budget Instructions are provided as Attachment B to this response. The budget instructions include the schedule and describe the guiding principles used to establish the corporate O&M and capital budgets.

There are four major changes between the 2013 and 2014 budget guidelines. The changes for items 2 through 4 were implemented in order to facilitate better tracking of the costs, which are set forth in Table 1 below.

1. Changes pertaining to the use of capital subledgers
   - Beginning this year, we will be using the 99999997 subledger to budget for transportation non-labor capital costs.
   - Also new for this year, we will be using the 99999998 subledger to budget for capital labor costs associated with work planned for IT projects.

2. Changes in merit increase. Table 1 below displays the merit increases for NSPM Company and Xcel Energy Services, Inc. for the first year of each of the two Budget Create cycles. For example, the increase of 3.0% shown for the 2014-2018 Budget Instructions pertains to 2014. The increase of 2.5% shown for the 2013-2017 Budget Instructions pertains to 2013.

3. Changes in warehouse rate

4. Changes in commercial travel fees

Table 1

			Benefit	Exempt	Non-Benefit	Other-Benefit	Union
Merit Increase	NSPM	2014 from 2014-2018 Budget Instructions	3.0%	3.0%	3.0%	3.0%	3.0%
		2013 from 2013-2017 Budget Instructions	2.5%	2.5%	2.5%	2.5%	3.25%
	XES	2014 from 2014-2018 Budget Instructions	3.0%	3.0%	3.0%	3.0%	NA
		2013 from 2013-2017 Budget Instructions	2.5%	2.5%	2.5%	2.5%	NA

			Energy Supply	Utility Group Stock Material	Utility Group Re-stock Material
Warehouse Rate	NSPM	2014 from 2014-2018 Budget Instructions	4.5%	15.0%	17.0%
		2013 from 2013-2017 Budget Instructions	1.0%	15.0%	17.0%

					Assisted online - Domestic		Assisted online - international		
			Unassisted online	Car/Hotel Only unassisted online	Minneapolis assisted	Automation assisted	Minneapolis assisted	Automation assisted	Agent Initiated - Domestic
Commercial Travel Fees	NSPM	2014 from 2014-2018 Budget Instructions	$ 11.00	$ 9.00	$ 28.40	$ 28.40	$ 28.40	$ 28.40	$ 30.15
		2013 from 2013-2017 Budget Instructions	$ 11.00	$ 9.00	$ 28.25	$ 28.25	$ 28.25	$ 28.25	$ 30.00

Witness: Anne Heuer
Preparer: Greg Robinson
Title: Manager
Department: O&M and Capital Reporting and Analysis
Telephone: 612-215-4631
Date: March 14, 2013

Corporate Budget Instructions

2013-2017 O&M Budget and Capital Budget

Revised March 2012

Date: March 1, 2012

From: Amy Stitt, Managing Director, Financial Performance and Planning

Reference: O&M and Capital Budget Instructions

The Financial Budget is a key component of the framework for developing supportable and attainable financial plans by legal entity, utility and jurisdiction. It is used to evaluate actual performance and aids management in making business decisions and monitoring ongoing financial performance for each Operating Utility (OpCo) and Xcel Energy consolidated. We must continue to increase the effectiveness of our overall business planning processes to successfully execute our strategic, operational and financial plans within the evolving dynamic environments that we conduct business. Specifically, within the budget process, we have developed some guiding principles to help us on this journey:

- Key assumptions within our strategic, operating and resource plans will drive our annual budget and quarterly forecasts;
- OpCo Presidents have significant decision-making authority for their OpCo and must collaborate with Business Area Leadership in developing each OpCo business plan;
- OpCo Presidents must collaborate together in arranging for services performed by the “shared service” business areas;
- Budget detail should be at the highest level possible that allows each organization to run its business effectively and account for its costs in the proper FERC accounts;
- **O&M budgets** will consist of **5 years** of monthly detail from previously two years;
- O&M forecasts, or updates to the budget, will reflect planned changes with OpCo and business area leadership support; and
- **5-year Capital budgets** are developed and updated between annual budget cycles to accurately and timely reflect any major changes to our capital investment plans.

The attached Corporate Budget Instructions (Budget Instructions), including the budget calendar herein, have been prepared considering these guiding principles and are to be used in preparing the 2013-2017 Operations and Maintenance Expense (O&M) Budgets and the 2013-2017 Capital Expenditure Budgets, including estimated project in-service dates. The following corporate guidance, and policies and procedures for preparing business area and legal entity budgets help ensure the Company’s O&M and Capital budgets are accurate, well documented and consistent with the Company’s ongoing business planning.

Expectations for this year’s budget development have not changed significantly from last year. Those expectations include the following:

O&M Budgeting:

- Budgets are well documented supported by workpapers with clear assumptions linking the budget assumptions to historical data (actuals).
- Identify business drivers for cost increases, identify areas where cost reductions have occurred as the result of productivity improvements, adhere to established policies and procedures, and are accurately input into budgeting tools
- Data and supporting documentation are clear, with the ability to understand and explain changes when comparing on an object or FERC account basis
- Expenditures are budgeted in the same object account and FERC account where the actuals are expected to be charged
- Budgets incorporate lessons learned and measurable changes resulting from variance analyses

Capital and Deferred Budgeting:

In addition to the above expectations,

- CIP/DSM and other rate recovery rider expenses and capital projects must be separately identified and budgeted
- Capital project cash flows are accurate beginning with the bridge year (actuals through March 2012 & forecast April-Dec 2012), carrying forward continuously through the budget period of 2013-2017, and in-service dates must be consistent with current project schedules, including the bridge year
- Careful attention is paid to routine parent work order details and accounting
- A focus on capital plant in-service is made such that, all current actual CWIP balances are examined and work orders that represent plant being used are placed in service in the accounting records before the budget begins.

Your business area financial leaders should be your first point of contact, however, if you have general budget questions or require additional information, please feel free to call me at 612-215-4623 or you can contact Erica Meyer Olson at 612-215-4564.

Table of Contents

2013 / 2017 O&M and CapEx Budget Development Timeline

For Calendar Year 2012 as of February 27, 2012

March 5, 2012	Budget Instructions issued
Mid March 2012	Issue Budget Documentation & Workpaper Requirements
Late March 2012	Issue O&M and Capital Spending Guidelines
March 19, 2012	PeopleSoft Load in CBS for 2013/2017 Budgeting Cycle
April 16, 2012	**Final Clearing Budgets Due in CBS – (clearing objects will be locked EOD – including labor)**
April 16 - 23, 2012	Validation of Labor Utilization
April 24, 2012	**All Labor Due in CBS (labor objects will be locked EOD)**
April 30, 2012	**Create 2013-2017 Budget version in CBS and ALS**
May 3, 2012	**Final Capital Budgets Due in CBS**
May 7, 2012	**Capital Financial Council Presentations due to Jeremy Johnson by 11am CT**
May 9, 2012	Run Labor Overheads with New Actuarial Information (EOD)
May 11-31, 2012	Complete GAAP and FERC Trend Analysis along with Regulatory Review
May 17-18, 2012	**Financial Council Review/Approval of Capital Budgets**
May 19–30, 2012	**Incorporate Final Capital Changes with Executive Approval**
May 21, 2012	**O&M Financial Council Presentations due to Jeremy Johnson by 11 am CT**
May 30, 2012	Preliminary Budget Capital Repository
May 31, 2012	**Final Budget Capital Repository and Power Plant Feed**
June 11 and 13, 2012	**Financial Council Review/Approval of O&M Budget**
June 14 - 25, 2012	**Incorporate Final O&M Changes with Executive Approval**
June 25, 2012	**Complete Packet of Preliminary Budget Documentation with Narrative and Variance Analysis**
June 26-July 26, 2012	Review of Preliminary Narrative and Variance Analysis
August 1, 2012	**Final Budget Documentation: Narrative and Variance Explanations Due**
August 31, 2012	**Budget Workpapers Due**

Green=Capital, **Blue=O&M**

The business areas may also provide business area specific deadlines for completion and review that must be met. Please contact the designated financial liaison/representative for your business area for specific dates (see *Business Area Contacts*).

The Corporate Budget Calendar is also available on the *Corporate Budgeting Home Page.*

Navigation Guide and References

Background

The O&M and Capital Reporting and Analysis department (Budgeting) within the CFO's organization is responsible for the coordination of two components of the corporate budget - the five-year O&M budget and the five-year Capital budget using the CompetiSoft Budgeting System (CBS). Financial Forecasting updates years 3-5 in the Competisoft Financial Model (CFM). The business areas, functional areas and legal entities across Xcel Energy input their O&M and Capital budget details into CBS.

The Budget Instructions summarize the corporate information that business areas need to prepare. The Budget Instructions are issued to members of the Financial Performance Team and all of the business area representatives. The business area's representative on the Financial Performance Team will be the principal contact throughout the budgeting cycle. They are also responsible for integrating the Budget Instructions and policies with business-area-specific instructions and communicating the integrated package to all members of their organization that will be participating in the budgeting process. The Budget Instructions are also available on the *Corporate Budgeting Home Page*.

The Budget Instructions are organized to be effective, efficient and as user friendly as possible for the business areas. The first section of the Budget Instructions provides an overview of the purpose and importance of the corporate budget, major changes from last year's Budget Instructions, and expectations of business areas in preparing budgets. The Corporate Budget Calendar is provided and contains important dates for key activities throughout the budget cycle. This section also provides information related to using the Budget Instructions and who to contact to answer budgeting questions.

The main body of the Budget Instructions is organized into three sections: Budgeting Labor Costs, O&M Budgeting and Capital Budgeting. Each of these sections provides users with relevant budgeting information (General Guidance), corporate assumptions and directives (Assumptions) and "must do" specific instructions (Requirements) to use in preparing that portion of their budgets. Appendices have also been included to provide users with budget tool and accounting policy information, as well as a glossary of terms applicable to budgeting.

As users prepare their budgets, they should remember that budgeting is a key component of the framework for developing supportable and attainable financial plans by legal entity, utility and jurisdiction.

Navigation Guide

Several features have been included to facilitate the use of the electronic version of these Budget Instructions in the development of O&M and Capital budgets:

- The Table of Contents allows users to click on a topic and be automatically directed to that specific section.
- Throughout the document "links" have been inserted. Users are automatically directed to the document being referred to when clicking on these "links" or underlined text.
- The Corporate Budget Calendar highlights the important corporate deadlines for the input and review associated with the budget process. It is essential that users adhere to the dates provided in the Budget Instructions. Business areas may provide supplemental instructions and may also establish business area specific deadlines for input and review of budget data that must be met. Please contact the designated financial liaison/representative for your business area for specific dates (see *Budget Help*).
- Guidelines for preparing the required Budget Documentation (a resource based summary of budget activity by business area) and Workpapers (detailed information to support budget dollars and related documentation) will also be distributed in March 2012. See the *Budget Documentation & Workpaper Guidelines* published on the Corporate Budgeting Home Page for more information.

- A Glossary of budget terms and acronyms is included in the Appendices.

References

This document provides links to the Corporate Budgeting Home Page where you can find electronic versions of the Budget Instructions and the Budget Documentation & Workpaper Guidelines as well as links to other helpful tools and information, including:

CBS References

- *CBS Training Guide*
- *Rules for Project Date Moves*
- *Troubleshooting CBS – FAQs*

General Information

- *Budget Documentation & Workpaper Guidelines*
- *Business Systems-IT Product Information*
- Business Systems Contacts
- *Company Travel and Employee Expense Reimbursement Policy*
- *Dues and Other Guidelines*
- *Environmental Budget Guidelines*
- *FERC Uniform Systems of Accounts Manual*
- *Fleet Chargeback Rates*
- *JD Edwards Regulatory Ledger Training*
- *JD Edwards Training*
- *Personal Communication Device Policy*
- *Service Company Training*
- *The Print Shop Price Sheet*

O&M References

- *Corporate Escalation Rates*
- *General Guidelines for Classifying Labor and Expenses to A&G or FERC Functional Accounts Policy*
- *O&M Object Account Description*
- *Employee Expenses Accounting Guide*

Capital References

- *Capital Asset Accounting Policy - Capital Budget Principles*
- *Capital Expenditure Budget Requirements Matrix*
- *Reason Code Definitions*

Budget Help

For questions on the budgeting process or treatment of area-specific O&M and Capital costs, contact the representatives below or call the Budget Hotline at 612-330-6077.

Energy Supply	Julie Linquist (NSPM O&M)	612-337-2249
Bill Wilcox	David Mills (SPS O&M & ES Service Organization O&M)	806-378-2727
financial leader	David E Olson (PSCo O&M)	303-571-7108
	Katie Remmen (ES Capital, Engineering & Construction)	612-330-5860
	Lynn Olson (Technical Services)	303-440-2530
Operations Services	Nancy Linnet (Environmental, Fuels)	303-294-2011
Vicki Beer	Ruth Montoya (Supply Chain)	303-628-2711
financial leader	Linda Richards (Fleet)	303-571-7443
Nuclear Generation	Mary Emanuelson (Capital, Nuclear Mgmt Support)	612-330-5850
Linda Erickson	Diane VanDeWalker (Prairie Island)	651-388-1121 x4183
financial leader	Jim Johnson (Prairie Island)	6513881121 ext 7301
	Lisa Grigas (Monticello)	763-271-5140
	Kari Gombos (Monticello)	763-295-1036
Nuclear Amortization	Charles Jacobs (Manager)	612-330-2834
Karen Everson	Troy Nyhus	612-330-5572
financial leader		
Distribution Operations/Gas Systems	Liz Gauna-Giacomini (O&M Manager)	612-330-1982
John Phibbs	Cherie McMillan (Capital Manager)	303-571-3644
financial leader	Vicky Earnest (NSPM/NSPW)	612-330-6313
	Min Xue (NSPM/NSPW)	612-330-6623
	Nate Harrington (NSPM/NSPW)	612-330-5869
	Dolores Landavazo (PSCo/SPS)	303-294-2129
	Bryan Craig (PSCo/SPS)	303-294-2357
	Gretchen Meyer (PSCo/SPS)	303-294-2014
Transmission	Mary Ohland (Capital)	612-330-1920
Scott Watson	Kelly Gustner (O&M)	612-330-5958
financial leader	Maya Toukatly (Support O&M)	612-330-6012
	Laurie Wold (Support Capital)	612-330-5510
Benefits	Todd Degrugillier (Manager)	612-330-6557
Mark Moeller	Kris Lindemann	612-330-5508
financial leader		
Shared Services Finance Orgs	**Corporate Services (Tony Russeth, Manager)**	
Kim Locker	Tony Russeth (Manager, Business Systems)	612-330-5933
financial leader	Darian Brend (Business Systems)	612-330-6008

	Cindy Curry (Capital)	303-571-7881
	Grover Mills (Property Services, Business Services)	303-294-2112
	Kimberly Hardy (General Counsel, Human Resources)	303-294-2010
	Nate Young (Customer Care/Bad Debt)	303-294-2258
	Peggy Stevens (Financial Operations, Strategy and Planning, CEO)	303-294-2817
	Cindy McShane (Chief Administrative Officer, Customer Care)	303-571-7359
	Michael Agcaoili (Public Policy and External Affairs, Corporate Other)	303-294-2949
Group Utility President	Raynard Gray (Manager)	303-294-2488
Janet Schmidt-Petree	Mike Hager	303-571-7472
financial leader	Kiem Thang	303-571-6523

Capital Asset Accounting Business Area Liaisons

Budget Organization	CAA Liaison	Phone
Corporate Services	David Adams	303-294-2094
Transmission	Ray Hetherington	612-330-5565
Distribution	Becky Dean	303-294-2395
Energy Supply NSPM	Carol Callahan	612-330-7659
Energy Supply NSPW	Dave Amans	715-737-2495
Energy Supply PSCo	Kris Jenson	612-330-5583
Energy Supply SPS	Denise LeGault	303-294-2093
Nuclear Generation	Jake Miller	612-330-1959

Budgeting Labor Costs

On March 19, 2012, a PeopleSoft load into CBS will update the current forecast to reflect any personnel changes that have occurred since the January 2012 PeopleSoft load. These are the current merit increases assumed for 2013-2017:

2013

Company	BENEFIT	EXEMPT	NON-BENEFIT	OTHER-BENEFIT	UNION
NSM	2.75%	2.75%	2.75%	2.75%	3.25%
NSW	2.75%	2.75%	2.75%	2.75%	3.25%
PSC	2.75%	2.75%	2.75%	2.75%	3%
SPS	2.75%	2.75%	2.75%	2.75%	2.9%
XLS	2.75%	2.75%	2.75%	2.75%	N/A

2014-2017

Company	BENEFIT	EXEMPT	NON-BENEFIT	OTHER-BENEFIT	UNION
NSM	3%	3%	3%	3%	3%
NSW	3%	3%	3%	3%	3%
PSC	3%	3%	3%	3%	3%
SPS	3%	3%	3%	3%	3%
XLS	3%	3%	3%	3%	N/A

Labor expense budgets are then created by identifying projected employee levels and appropriate wage rates for each budget year. The wage rate of each active employee will already be in the system at the beginning of the budget process through the PeopleSoft load. The budget system also includes estimated overall wage percentage increases by labor category (union vs. non-union, etc.) that are applied to each employee's wage rate to estimate the budget year labor dollars. Labor budgets should be direct charged when possible to the company benefitting from the services to be provided.

General Guidance

Labor Resources

Xcel Energy employees are divided by labor resource categories in order to better define their assignment to JDE business units. The resource categories are:

- Exempt – full-time salaried employees
- Benefit – hourly full-time non-union employees
- Other benefit – hourly part-time benefit employees
- Non-benefit – hourly part-time temporary employees without benefits
- Union – full-time hourly bargaining employees
- Contract – see the document titled *O&M Object Account Description* published on the Corporate Budgeting Home Page for specific JDE object account uses
- Premium time – shift differential pay
- Overtime – straight time, double time or time and one-half by each labor category

Labor Management

Throughout the year, PeopleSoft data will be refreshed in CBS after normal wage increases go into effect. These updates take place in January (NSPM, NSPW and Nuclear union), March (non-bargaining), July (PSCo union) and November (SPS union). Users will be notified when these refreshes occur and are required to validate headcount following the update. Users are also required to verify that employee labor includes annual wage increases; especially if new employees are added after the wage increases are loaded.

Assumptions

General Wage Increase

A general wage increase will be applied in the 2013-2017 budgets systematically as noted above. For bargaining employees, the wage increase will be based on the contract agreements with additional guidance from Compensation and Executive management for the years not covered by a contract.

Hours Per Month

Available labor dollars in CBS are calculated based on the available hours per month. The number of available hours per month varies from year to year, depending on the timing of weekdays/weekends for each calendar month. The schedule below shows the hours per month used in the calculation of the monthly spread of hours in CBS.

	Exempt, Benefit, Union & Other Benefit				
Year	**2013**	**2014**	**2015**	**2016**	**2017**
Jan	184	184	176	168	176
Feb	160	160	160	168	160
Mar	168	168	176	184	184
Apr	176	176	176	168	160
May	184	176	168	176	184
Jun	160	168	176	176	176
Jul	184	184	184	168	168
Aug	176	168	168	184	184
Sep	168	176	176	176	168
Oct	184	184	176	168	176
Nov	168	160	168	176	176
Dec	176	184	184	176	168
Total Hrs	**2,088**	**2,088**	**2,088**	**2,088**	**2,080**

	Non-Benefit				
Year	**2013**	**2014**	**2015**	**2016**	**2017**
Jan	176	176	168	160	168
Feb	160	160	160	168	160
Mar	168	168	176	184	184
Apr	176	176	176	168	160
May	176	168	160	168	176
Jun	160	168	176	176	176
Jul	176	176	176	160	160
Aug	176	168	168	184	184
Sep	160	168	168	168	160
Oct	184	184	176	168	176
Nov	160	152	160	168	168
Dec	168	176	176	168	160
Total Hrs	**2,040**	**2,040**	**2,040**	**2,040**	**2,032**

Incentives

The executive officer and corporate incentive plan programs are budgeted corporately at the legal entity level. Business areas should not include any amounts in their budgets for these compensation programs.

Business area specific incentives and bonuses are discussed in the O&M Budgeting section of these instructions (see *Employee Incentives and Other Compensation*).

Benefit Employee Labor Loadings *(Pension and 401K, Healthcare, Worker's Compensation, Incentive & Payroll Taxes)*

Benefit employee labor loadings are calculated within CBS and are budgeted corporately at the legal entity level. Business areas should not include any amounts in their budgets for these loadings. The labor loading rates will be applied by CBS to budgeted productive labor with the resulting labor loads following budgeted labor to produce a total labor budget by JDE business unit.

Non-Productive Labor Loading

Non-Productive labor loadings are also performed within CBS. Non-Productive Time (NPT) is time that an employee is not working because of personal time off (PTO), floating holidays, jury duty, etc. In order to accurately develop rates for non-productive labor, it is critical to have an accurate monthly pattern of base wages. This requires an accurate count of employees and accurate rates for each employee. On an annual basis, CBS allocates approximately 83% of wages to productive labor and approximately 17% to non-productive labor. The non-productive labor loading rate is applied to O&M productive labor to determine the amount of O&M non-productive labor to record in object account 711143-Non-Productive Labor.

Attrition Labor Loading

A negative attrition rate will be loaded on to productive labor in order to account for expected corporate vacancy rates. The following JDE object accounts are used to record attrition:

- 618099 - Fuel Handling Labor-Attrition
- 618419 - Fuel Procurement Labor-Attrition
- 618429 - Nuclear Fuel Procurement Labor-Attrition
- 711146 - Productive Labor-Attrition
- 730380 - CWIP Productive Labor-Attrition
- 747125 - Clr Productive Labor-Attrition
- 748118 - Def Productive Labor-Attrition
- 740398 - RWIP Productive Labor-Attrition

Business areas should remove all negative pseudos (vacant positions) currently in CBS for attrition. Managers should not be budgeting for attrition. Business areas are responsible for managing to the total of productive labor less attrition.

Requirements

Naming Convention for Pseudos

Due to ongoing pseudo reporting, a naming convention has been designed in order to report on the types of pseudos in each business area. In the 255 character description field, pseudos must begin with one of the following two character designations followed by a dash (-):

- **Replacement (PR)** – Employees who have been terminated or transferred, and a replacement is anticipated. Generally a pseudo for a position that is currently vacant, possibly for a position that will be vacant in the near future, assumes the current employee is zeroed out now or in the near future.
- **New Hire (PN)** – New positions that have been formally approved as part of the workforce plan. Generally a pseudo for a position that adds to total staffing level due to a new or expanded function.
- **Advanced Hire (PA) –** Positions that will be vacated in the future where multiple years of training are required by the position or a union contract.
- **Intern (PI) -** A pseudo to identify open intern positions.

Labor Utilization Validation

After the March 9th PeopleSoft load has been completed, users should verify in CBS that the employees and base wages for each JDE business unit are correct. Please add, delete or create pseudos (vacant positions), and update wage rates, where necessary, to reflect promotions, etc. If a new pseudo is created, users must fill in the appropriate hours in the NPT box for each year. See the *CBS Training Guide* published on the Corporate Budgeting Home Page for more information. Each business area is responsible for reviewing all of their labor departments to verify the following:

1. Labor is fully utilized (i.e., distributed to O&M or Capital)
2. Employees are shown under the correct labor department
3. Pseudos are eliminated in all cases where the vacant position has been filled
4. Pseudos have been added for those positions that are approved as part of the workforce plan, but not yet filled
5. Employees that need to be transferred to another labor department have had a personnel action form (PAF) completed prior to making the transfer in CBS

Users should run a labor utilization report in CBS to assist in validating that labor is fully utilized. As noted on the Corporate Budgeting Calendar, the period from April 16th through April 24th will be used to complete a final corporate check on labor utilization, and to ensure labor aligns with the workforce plan. Please contact Irina Demuth at 612-330-1978 for any questions regarding labor utilization.

O&M Labor

O&M labor entered into CBS must be entered using object account of 711142–Productive Labor.

Capital Labor

Labor that is direct charged to a capital work order should be entered into CBS in object account 730390-CWIP Productive Labor, or 740399-RWIP Productive Labor, with a subledger "99999999" and a subledger type "W." Capital labor charged to NSPW should use the CWIP or RWIP objects with a subledger "99999997" and a subledger type "W." Labor indirectly charged through the Engineering and Services (E&S) overhead rate should use the object account set up for the type of work being completed with a subledger "99999998" and a subledger type "W."

O&M Budgeting

The purpose of the O&M budget is to forecast operating and maintenance expenses for the next five years. The business areas are responsible for developing the five-year detailed O&M budget by legal entity and business area, and entering the information into the current forecast version of CBS. Detailed O&M budgeting is required for 2013-2017.

Each business area is responsible for reviewing its O&M budget to ensure the budget is consistent with on-going business planning requirements. After the business area executive has approved the budget; it is presented to the Financial Council for their approval. If the Financial Council requests any revisions, the changes are made in CBS by the business areas.

There are two types of expenses included as part of the O&M budgets: labor expenses and non-labor expenses. The labor expense portion of the O&M budget was discussed in the previous section. Non-labor expenses are budgeted in several categories or cost components. These categories are identified for each business area and are designed to assist in providing an overall summary of major cost component areas that are discussed later in this section.

General Guidance

CBS Instructions

The O&M input tool for the 2013-2017 budget is CompetiSoft Budget System (CBS). CBS is configured to build budgets consistently with actual accounting data. JD Edwards (JDE) is set up to interface with CBS. JDE loads actual accounting data into CBS and the Allocation Ledger System (ALS) for comparison and variance analysis. Business areas are accountable for the reporting of budgeted information and variance analysis from all reporting views including, but not limited to, legal entity, business area and regulatory reporting. The Business Objects reporting tool provides several universes that can be used for this variance analysis.

All budgeting occurs in the current forecast version. Periodic copies may be made to coincide with the various deadlines. Additional information regarding the specific dates of the copies will be communicated as the budget process progresses.

The following documents have been prepared to assist users. See the links below, or reference the document that is also published on the Corporate Budgeting Home Page.

CBS Training Guide

CBS Tool Link

Troubleshooting CBS – FAQ's

JDE Subledger and Subsidiary Field Guidance

Each labor and non-labor budget record is assigned to an account string (JDE business unit, JDE object account and JDE subledger (when necessary)). The account string is used to assign the expense to the appropriate legal entity, as well as the appropriate FERC account and utility (e.g., gas, electric). This assignment to the account string is also used as the basis to develop electric or gas cost of service studies. It is important to budget to the same object and FERC where you expect your actuals to be charged. Instructions on JDE subledger fields and subsidiary fields used in the development of O&M budgets is contained in the Appendices, and can be accessed by the following link: *JDE Guidance*.

Budgeting Principles

Labor costs of employees reporting to, and non-labor costs controlled by, the management of each group must be 100% budgeted and paid for by that manager. For example, the manager who chooses the consulting company and oversees their work pays the charges for consultants and contractors. Cross-charges between departments do not move the budget dollars or variance responsibility to another area. It is recognized that some invoices, such as corporate dues, may be split among management when agreed to by all parties.

Assumptions

Environmental

Environmental expenses associated with air, water and waste remediation should be budgeted in accordance with the *Environmental Budget Guidelines* published on the Corporate Budgeting Home Page.

Subscriptions On-Line

Object account 725005-Subscriptions On-Line, should include expenses for subscriptions and reference materials which are received using an online tool, or reports or data which are received electronically using an online tool. Examples include any Information Service Provider (ISP) or third-party hosted systems provider.

Facilities

The Property Services organization is responsible for budgeting all O&M costs for facilities managed by Property Services (e.g., headquarters, call centers, service centers) including: facility rental or lease costs, and all costs associated with the ongoing activities necessary to operate and maintain the leased and owned facilities, unless covered by the rental or lease agreement. This includes such items as climate control, lighting, snow removal, lawn service, landscaping, grounds maintenance, mowing and sprinkler systems when not covered by the applicable rental or lease agreement.

Facilities space and operating and maintenance costs are budgeted by Property Services, except for the following:

- Fleet, Sourcing, and Logistics as these areas budget their facilities costs within their own clearing accounts,
- Energy Supply which budgets for their own plant facilities operations and maintenance costs, and
- Electric and gas use costs at operational facilities, such as gas regulators sites, microwave and radio towers, power plants, substations, etc.

Requests for facility services (O&M and capital) should be submitted to Property Services. For more information, please contact Grover Mills at 303-294-2112.

Copiers – Property Services managed copiers only

Property Services will continue to manage and budget for the corporate copier program. Business areas will remain responsible for paper, color toner, and special request copier costs, including copier lease, maintenance, usage (meter) charges, toner, and staples. Contact Paul Thompson at 612-330-6287 if you have questions about whether or not your copier is managed by Property Services or is considered a special request copier.

Printing Services

Business areas will remain responsible for budgeting their printing costs. The Print Shop Price Sheet provides estimated costs for various print shop services.

Budget printing costs to JDE object account 714100-Print/Copy-Other for O&M expense, 748170-Def Materials for deferred expense, account 731800-CWIP Materials for Capital expense, or 747510-Clrg-Print/Copy for clearing expense.

Postage/Carrier (e.g., FedEx)/Inter-Company Mailings

Business areas are responsible for budgeting all USPS postage. All FedEx, UPS and other carrier mailings will continue to be charged in full to the sender's business area. Property Services does not budget for any mailings sent by the business areas via FedEx, UPS, or other carriers. Intercompany mailings will continue to be budgeted by Property Services. Business areas are not responsible for budgeting inter-company mail.

Budget postage costs to JDE object account 723400-Postage for O&M expense, 748210-Def Postage for deferred expense, and 747920-Clr Postage for clearing expense.

Facility Waste

Property Services will continue to manage and budget for waste containers at Property Services managed facilities. These containers are intended for common facility waste only (i.e. the contents of employee, office, and lunchroom waste containers). Business areas will be responsible for managing and budgeting for the disposal of project and equipment waste (i.e. poles, cross arms, hardware, and equipment containers).

Information Technology (IT)

All IT capital project budgets are budgeted by Business Systems and should not be part of the business areas' budgets. This includes software implementations, as well as hardware capital purchases for PCs, LANs and printers that meet the capital guidelines. Business areas should not budget for software/hardware projects. If you have any questions, contact Diane Prentis at 612-330-5744.

If you have a new IT initiative, such as a new application system, new support or a non-standard purchase, please contact Business Systems area directly to discuss your initiative. The contact list can be found under the following link Business Systems Contacts. This information is important so that Business Systems can budget and plan accordingly.

Efficient use of Personal Computing assets enables Xcel Energy to leverage volume purchases, minimize support costs through product standardization, promote compatibility between IT assets and Xcel

Energy's computing environment, monitor compliance with software licensing/data security, and maximize return on investment by carefully managing the lifecycle and use of these assets. . For additional information about IT management standards please refer to the following link: *Business Systems Standard*

IT Investment Closed Loop Process

Business areas that have projects that have been approved by the IT Investment Council where hard savings will be realized are required to budget the savings that were presented for all applicable periods. If you have any questions, please contact Jeremy Johnson at 612-215-4647 or Greg Robinson at 612-215-4631.

Insurance Premiums

Liability and Property insurance (insurance expense related to insurable accidental events) will be budgeted corporately by Hazard Insurance. Business areas should not include any amounts in their budgets. If you have any questions, contact Mike Anderson at 612-215-5366 or John Hernick at 612-215-5349.

Supply Chain Sourcing - Category Management

Supply Chain Sourcing has identified certain key categories of spend for which it gathers market information and leverages spend of the company to pursue strategic contracting strategies, including price reductions, volume discounts, lead time preferences, etc. All budgets impacted by the categories below should contact the assigned category manager for the most current information regarding price assumptions for the spend category.

Category	Category Manager
Boiler Systems, Boiler Maintenance Services, Turbine/Generator Services	William Smith
Cable & Wire, Circuit Breakers, Transformers (Power)	David Reitz
MRO / VMI	Rick Pelletier
Chemicals, Gases & Lubes	Brian Hastings
Engineering Services	Brian Owen
Metal Structures, Wood Poles, Vegetation Mgmt	Bob Kunze
Travel Services, Staff Aug. / Personnel Services	Bob Wagner
IT and Telecom	Bob Wagner

Purchasing Rates

Each business area is responsible for budgeting purchasing loads. A loading rate of approximately 1.0% (actual allocation rates may differ slightly depending upon jurisdictional procurement activity and compliance to Corporate Policies) is to be applied to all purchases of material and services, including inventory, subject to a transactional limit. Purchasing loads should not exceed $3,500 per invoice per purchase order (PO) or PO release per invoice. For example, an invoice of $550,000 for material purchases for one PO would receive a purchasing load of $3,500. Purchasing loads do not apply to Nuclear purchases. For more information, contact Linda Richards 303-571-7443 or Ruth Montoya 303-628-2711.

Business areas are also responsible for budgeting Supply Chain labor and expenses in instances where sourcing/purchasing employees are performing work for a specific capital project. Capital project codes must be supplied to the Supply Chain sourcing and purchasing personnel prior to commencing work on a project in order to accurately charge labor and any associated expenses.

Warehousing Rates

Each business area is responsible for budgeting warehousing loads. Due to different charging methodologies and systems, different rates apply for the Utilities Group and Energy Supply business areas as described below:

Energy Supply: Apply a 1% warehousing rate to the value of materials issued, not to exceed $3,500 for any single item. This provides for all storeroom transactions (receiving, handling, storing & issuing). If you have any questions contact Ken Heupel at 720-497-2040.

Utilities Group: Apply the following warehousing rates to purchases of materials.

Stock material (handling, storing, issuing and delivery)

NSPM	15%
NSPW	13%
PSCo	15%
SPS	11%

Re-stock material: NSPM, NSPW, SPS – 17%; PSCo – 0%

Please, contact Ruth Montoya at 303-628-2711 or Linda Richards at 303-571-7443 with questions.

Joint Ownership Share

Special accounting treatment may apply when budgeting costs to jointly owned facilities. For guidance, please contact:

Carrie Dyer	303-294-2385	General joint ownership accounting
Chris Keiss	970-276-2226	Hayden Station (PSCo)
Stan Rogers	719-549-3752	Comanche Station (PSCo)
Annie Lord	719-549-0321	Comanche Unit 3 (PSCo)
Todd Griesert	763-261-3106	Sherco Station (NSPM)

Direct Support of Outages at Prairie Island or Monticello Nuclear Plants

The direct support of nuclear outage related expenses (i.e., labor and employee expenses) may be eligible to be amortized over the nuclear plant operating cycle. If you plan to support nuclear outages during this budget cycle, please contact Stephen Blegen for Monticello at 763-295-1627 and/or Mark Aeling for Prairie Island at 651-388-1121 x5228 for a determination whether the work meets the outage accounting policy and for a subledger to use in the development of the budget.

Requirements

Budget Documentation and Workpapers

Budget Documentation is required for all business areas by operating company. This is a broad, resource based summary of budget activity for each business area. The format and level of detail required is consistent for all of the business areas and operating companies. See the *Budget Documentation & Workpaper Guidelines* published on the Corporate Budgeting Home Page for specific requirements and templates. A checklist is provided in the Budget Documentation & Workpaper Guidelines. Please use this in preparing your documentation. It is important to remember that maintaining well-documented budget assumptions and explanations to support your budget is a critical element of managing the business and may be used to support forecasted test year rate case filings.

Budget Workpapers are also an integral part of the budget process for all business areas. Budget Workpapers should provide detailed information to support budget dollars and budget documentation.

IT O&M Requests

All requests for IT products and services (adds/moves/changes, hardware, software, IT support, systems access, security updates, etc.) must be submitted through *Mercury*, the company's IT request system. Business areas that expect to need new IT products and services for the 2013-2014 budget years should communicate this to the Business Systems Business Technology Executives (see Business Systems Contacts.) The Business Systems Business Technology Executives need to incorporate these expenses in the Business Systems budget, and the BTE's need to prioritize and approve these IT initiatives.

Monthly Budgets

For the budget to be most useful in managing the company's business and monitoring financial performance, it is critical that the monthly budget accurately reflects when users expect to incur expenses during the year. Best estimates of when planned costs will be charged to a JDE business unit should be used in the development of the monthly budget, as this provides support for estimating cash flow requirements. The monthly budget is as important as the annual budget. The monthly budget deviations (and forecast updates), which are reported throughout the year, are a primary indicator used to monitor financial performance throughout the year. The monthly budget estimates may also be used in the event of a rate case filing in which the test period crosses two calendar years. Do not budget the same amount for each month unless the budgeted expense is anticipated to be incurred in this manner. Any escalation of costs should be based on known factors such as historical costs or anticipated increases. Your basis for increase should be well documented as part of your budget workpapers. For general inflation increase estimates refer to the *Corporate Escalation Rates* published on the Corporate Budgeting Home Page.

Third-Party Billings

Business areas must include in their O&M budget all expenses that are billed to third parties (i.e., parties outside of the Xcel Energy holding company system). Examples of third-party billings include: relocating distribution and transmission facilities for the accommodations of others, repairing damages to company property and working on customer owned electric distribution facilities. The proceeds from third-party billings must be accounted for in the revenue accounts, so do NOT net the proceeds with the O&M expenses, and do NOT enter the revenue into CBS. Revenues for billing work orders in JDE will automatically be calculated in ALS and then sent to the CompetiSoft Financial Model (CFM). Business areas do NOT need to send their revenue information to Financial Forecasting for input into CFM since the revenues will automatically be calculated. However, revenues related to billings NOT set up as billing work orders in JDE, need to be submitted to Financial Forecasting for inclusion in CFM.

For example, if NSPM incurs $2,000 in O&M expense for Right-of-Way (ROW) maintenance of a transmission line that is billed to another utility company (not part of the Xcel Energy holding company system), the $2,000 expense is budgeted in O&M expense, and the proceeds from the billing are budgeted in CFM under Other Electric Revenue. Please contact Erin McGuire at 612-337-2331 if you have billings outside of the JDE billing work order process.

Capital billings should not be included in the O&M budget, but rather as capital expenditures using the appropriate object account for such billing.

Service Company must bill all O&M costs to another Xcel Energy company. Once the O&M costs are billed to the appropriate Xcel Energy company, they can then be billed to the third party. Generally, the Service Company expenses are billed to one of the operating companies, unless the third party billing is for additional expenses incurred for an Xcel Energy company that has been sold. In that case, Service Company bills the intermediate or parent holding company of the sold company, and then the intermediate or parent holding company bills the third party. Revenue is recorded on the company (operating or holding company) that billed the third party and not on the Service Company.

Employee Incentives and Other Compensation

Incentives

Any business area specific incentive cost that is in addition to, or different from, executive officer or corporate incentive plan programs must be budgeted within each business area in object account 711230-Incentive. Costs budgeted to this object account must be for incentive plans that have been pre-approved by Human Resources.

Bonuses

Any business area specific bonuses above and beyond the corporate incentive plan program must be budgeted within each business area to object account 711270-Other Compensation. The Spot-On Bonus Program is budgeted at the corporate level and should not be included in business area budgets.

Employee Performance Recognition
This includes employee performance recognition such as Thank You's, Above & Beyond awards, Premiere Choice awards, company store items and recognition meals presented to acknowledge employees for a specific business related action or result. This should not be budgeted by individual business areas as it is budgeted corporately in object 721850.

Safety Recognition
Safety Recognition is the responsibility of individual business areas. Object account 721800 should be used to budget for any safety related recognition.

Life Events
Life events include promotion, retirement or a special occasion. This should be budgeted by individual business areas in object 721810.

Non-Recoverable Recognition
This object account 721851 is for year-end celebrations, which is only to be used if there is corporate approval and notification from management that funds are available. This will be evaluated each year and is at the discretion of The Company. This should not be budgeted by individual business areas, or used for actuals without corporate approval.

Consulting Services and Contract Labor

Legal Consulting Expenses
The Legal Services department is responsible for managing all legal matters, including engaging and approving the use of outside legal vendors. Internal business clients and in-house counsel may reach an agreement that business areas will bear the cost of certain legal matters. Legal Services will relay this information to the appropriate finance person in the particular business area. During the budget process, business areas must contact Legal Services to convey information related to projects that are anticipated during the 2013-2014 budget years that require assistance from Legal Services.

Contact Deb Meuwissen at 612-215-4545 or Kimberly Hardy at 303-294-2010 if you have any extraordinary projects that will require significant legal services, so the Legal Services' budget can be planned.

Other Consulting Expenses
For additional guidance on budgeting consulting and professional services in JDE object accounts please see the document *O&M Object Account* Description published on the Corporate Budgeting Home Page.

Contract Labor
Object account 712110-Contract Labor should only be used for expenses for persons who are engaged in short-term (less than a year), temporary or special purpose work that is supervised by a company employee. It includes temporary labor payable to a third party that replaces company labor for routine daily activities. It does not include expenses for employees of the company.

Contract LT Outside Services
Object account 713050-Contract LT Outside Services, should include expenses for persons who are engaged in long-term (more than a year) special purpose work. It includes, but is not limited to, the following services: tree trimming, meter reading, construction crews, scanning and imaging invoices or professional outside services that have material costs. It does not include: facilities operations and maintenance, printing, copying, office machine maintenance, cell phones, office supplies or expenses for employees of the company.

IT-Personal Communication Devices and IT Supplies

Each business area is responsible for budgeting personal communication devices and consumable supplies for their business area. Budget communication device costs in object account 715600-Personal Communication Devices.

For information on personal communication devices, refer to *Personal Communication Device Policy*

Budget fax machine leases in your business area in object account 723130-Equipment Rental. Fax machine leases should be budgeted by the business area primarily using the machine, unless otherwise covered by Property Services.

Budget other IT supplies (printer cartridges, pager batteries, projectors, etc.) in your business area using object account 714000-Materials.

Budget other printing service costs (e.g., Kinko's) in your business area using object account 714100-Print/Copy–Other.

Note that the following JDE object accounts can only be used by IT:

- 715100 - IT Hardware Maintenance
- 715200 - IT Hardware Purchases
- 715300 - Software Purchases
- 715400 - Software Licenses
- 715500 - Software Maintenance
- 715700 - Network Services
- 715710 - Network Voice
- 715720 - Network Data
- 715730 - Network Telecom
- 715740 - Network Radio/Pgr/MW
- 715800 - Mainframe Services
- 715810 - Distributed Systems Services
- 715820 - App Dev & Maint
- 715830 - Project Office
- 715900 – Application Service Provider

Employee Expenses

Employee Expenses include non-office supplies, reimbursable expenses incurred on the job, individual training, and similar items. When traveling, this includes meals, food items (including catering onsite/offsite meeting refreshments), offsite meeting/event, lodging, parking, telephone calls, tolls and other transportation expenses.

The following sample object accounts are available to accurately account for employee expenses: Also refer to *the Concur Expense Report Object Account Codes* for a complete list including definitions of expense types and their corresponding JDE object accounts.

- 721005 - Airfare
- 721010 - Car Rental
- 721015 - Taxi/Bus
- 721020 - Mileage
- 721025 - Conferences/Seminars/Training
- 721030 - Hotel
- 721035 - Meals – Employees
- 721040 - Meals – Including Non-Employees
- 721045 - Parking
- 721050 - Per Diem
- 721055 - Safety Equipment

- 723850 – Recognition - Entertainment
- 721060 - Other

All employees are expected to use sound judgment and plan business travel to minimize costs. In addition, Xcel Energy has negotiated discount or contract rates with its preferred vendors. As budgets are developed for employee expenses, take this information into consideration. The *Company Travel and Employee Expense Reimbursement Policy* also includes additional information. In addition to these items, there are specific requirements for the employee expenses addressed below.

Entertainment expenses are not considered employee expenses and should not be budgeted in the above accounts. Entertainment, including travel, meals and alcohol, should be budgeted in object account 723855-Other Deductions. Tickets for entertainment events should be budgeted in object account 723854-Deductions Corp Tickets. The *Company Travel and Employee Expense Reimbursement Policy* includes additional information on Entertainment expenses. The following are examples of entertainment accounts:

- 723854 – Entertainment - Tickets
- 723855 – Entertainment – Meals

Air Travel
Use object account 721005-EE Airfare for all air travel costs. Budget air travel expenses in the JDE business unit that will be used when booking your flight.

Corporate Travel – There are no direct passenger charge backs for travel on the Xcel Energy corporate aircraft. Corporate jet expenses will reside in the Aviation Services' budget. Business areas are not responsible for budgeting for these expenses. Travel on corporate aircraft is limited. See the *Company Travel and Employee Expense Reimbursement Policy* for priority in using company aircraft. If you have any questions, contact Harold Hyman at 612-215-4681.

Commercial Travel – The Carlson Wagonlit travel fees are slightly reduced, but please note that certain of the fees were not booked to the individuals BMO cards. Starting in 2012 and for the 2013 budget, see table below for the fees that will be processed against the BMO card (last column). It is highly recommended to use the GetThere travel tool to book air/hotel/car to take advantage of corporate discounting and other benefits. Each area is responsible for budgeting the service fee in addition to their air travel costs.

Description	2011 Fees Total Fees	2011 BMO Card Fees	2012-2014 BMO Card Fees
Unassisted online	$11.70	$9.00	$11.00
Car/hotel only unassisted online	$9.00	$0.00	$9.00
Assisted online - Domestic			
Minneapolis assisted	$33.24	$25.00	$28.25
Automation assisted	$33.24	$9.00	$28.25
Assisted online - International			
Minneapolis assisted	$33.24	$25.00	$28.25
Automation assisted	$33.24	$9.00	$28.25
Agent Initiated - Domestic	$28.94	$25.00	$30.00
Agent Initiated- International	$39.71	$35.00	$30.00
Car /hotel only - agent initiated	$5.00	$0.00	$5.00

Car/hotel only assisted online	$9.00	$0.00	$9.00

For additional information, please see *Company Travel and Employee Expense Reimbursement Policy*.

Corporate Tickets
Tickets purchased for Nuggets/Timberwolves basketball games, Wild/Avalanche hockey games, Twins/Rockies baseball games, Broncos/Vikings football games, Opera, Orchestra Association and other social events should be budgeted to JDE object account 723854-Deductions Corp Tickets. Budget food and drinks purchased at these events to JDE object account 723855-Other Deductions.

Employee Move-Related Costs
Business areas are responsible for budgeting the costs associated with adds/moves/changes that relate to physically moving boxes or building/changing cube walls. The average cost of moving an employee is $500. Budget these costs to object account 723040-Adds/Moves/Changes. Property Services will charge the costs to your JDE business unit as they occur. If you have any questions, contact the appropriate representative for your state (see *Project/Tenant Services Contacts*).

Spouse Expenses
Executive approval from Senior Management must be obtained before spouse expenses can be included as a company expense. Spouse expenses may include airfare, lodging and meals incurred on an approved business trip, or for attending company functions/festivities. Budget officer's spouse or delegated employee's spouse expenses to JDE object account 723855-Other Deductions. In addition, these costs must be billed to the Xcel Energy Holding Company. To ensure these costs are billed to the Holding Company use the JDE subledger “999101” with a subledger type “W.”

Office Supplies Expense
Use object account 721500-Office Supplies to budget for office supplies. Office supplies include pens, pencils, paperclips, paper (copier, tablets, etc.), staplers, staples, toner cartridges, calculators, holders and containers for any of the above items, calendars, hole punches, desk cleaning supplies (Clorox wipes, canned air for blowing off dust and dirt, etc.), folders/binders (3-ring, report, etc.), tape (scotch, duct, masking, etc.), tape dispensers, computer accessories (mouse pads, wrist pads, monitor risers, etc.), envelopes, Post-Its, glue, phone headsets, and similar items. *Note: Keyboards and mice must be coded to IT Hardware Purchases.*

Do not code office supplies to Employee Expenses or Materials.

Transportation

Fleet Vehicle and Equipment Rates
To facilitate budgeting, all fleet vehicles and equipment for 2013-2014 will be charged by the hour. This approach works best to accommodate the use of the Passport Work Management System, and will enable fleet costs to flow to projects on a daily basis.

In order to comply with corporate accounting guidelines, rates are reviewed each month and adjusted periodically as needed.

Each business area is responsible for budgeting vehicles and equipment. Fleet costs are required to be budgeted at a detailed level in the appropriate JDE object, see list below.

- 618305 – Fuel Handling Fleet
- 681023 – COGS Transportation Fleet (HomeSmart only)
- 722000 – O&M Transportation Fleet Cost
- 732700 – CWIP Transportation Fleet Cost

- 742700 – RWIP Transportation Fleet Cost
- 747810 – Clearing Transportation Fleet Cost
- 748195 – Deferred Transportation Fleet Cost

Please see the document *Fleet Chargeback Rates* published on the Corporate Budgeting Home Page for the hourly rates provided for each jurisdiction. The rates are designed to cover all of the costs associated with the vehicle or equipment. If you have any additional questions, please contact one of the following people: Amarillo – Ron Grady at 806-378-5416, Minneapolis – Wes Worthley at 612-630-4508, Denver – Ed Spencer at 303-571-3700, Kay Ozanne at 303-571-7945, or Mark Hennesy at 303-571-3809.

Pool Cars
Pool vehicles are available in the following locations:

- Colorado: Lipan Distribution Center (LDC), Materials Distribution Center (MDC), 1800 Larimer, Boulder Service Center, Grand Junction Service Center
- Texas: Amarillo Tower, Amarillo I-40 Garage, Amarillo Southwest, Lubbock
- New Mexico: Roswell
- Minnesota: Chestnut Service Center, 414 Nicollet, Maple Grove Service Center, Rice Street Service Center, St. Cloud Service Center, Newport Service Center, White Bear Lake Service Center, Faribault Service Center, Mankato Service Center
- North Dakota: Fargo
- Wisconsin: Sky Park, Rice Lake Service Center, Menomonie Service Center, Ashland Service Center, Abbotsford Service Center, Amery Service Center, Hudson Service Center, La Crosse Service Center, Eau Claire Western Ave. Service Center
- Michigan: Ironwood Service Center

Pool vehicles are supported by the Fleet organization. Each business area is responsible for budgeting for pool car usage. These costs will be charged back to each user's JDE business unit. For hourly rates on vehicles, divide the monthly rates listed in the *Fleet Chargeback Rates* published on the Corporate Budgeting Home Page.

Casual Use Rate
Employees using their personal vehicles for company business are reimbursed via Concur at the IRS Standard Mileage rate (2012 = $0.555 per mile, 2013 = $0.57 per mile). This rate is expected to increase 2% to 4% annually for 2013-2017. This expense must be budgeted under Employee Expenses as in the past. Casual Mileage is analyzed quarterly, and employees averaging over 1,000 miles per month in Casual Use should be transitioned to an assigned company vehicle. Please contact Mark Hennesy at 303-571-3809 if this is the case.

Dues, Contributions and Sponsorships

A company policy has been implemented regarding dues, contributions and sponsorships to ensure that the company remains in compliance with reporting and regulatory requirements.

See the document called *Dues and Other Guidelines* on the Corporate Budgeting Home Page for the policy related to each type of expense.

Please contact Julie Rushton at 612-330-2809 for questions related to due, contributions and sponsorships and contact Mary Pope 612-330-6574 regarding regulatory treatment.

O&M Projects with Special Rate Treatment

All eligible O&M projects and/or eligible expenditures associated with rate riders or other special rate treatment must be updated with the most accurate estimates for the budget, as well as monthly forecast updates. Each project should be budgeted separately to facilitate identification. Examples of such projects/expenditures include operating and maintenance costs at the company owned wind farms, Sherco and King plant mercury sorbent related costs, and the various distribution initiatives associated with the Central Corridor project.

Legal Settlement Expenses

Xcel Energy business areas are responsible for bearing the costs of legal settlements not covered by insurance. Allowance for settlements should be budgeted under object account 723480-Injuries & Damages by the business areas at a high level, not specific to any particular matter, based on the business area's three-year historical average settlements paid. Verify that you've budgeted to the correct utility (electric, gas, common) as well. During the budget process, business areas should contact Legal Services to coordinate information and budgets for settlements anticipated during the 2013-2014 budget years. Contact Deb Meuwissen at 612-215-4545 or Kimberly Hardy at 303-294-2010.

Capital Budgeting

The budgeting of capital expenditures and additions to plant in service includes identifying and prioritizing resources to support operations and future plant investments. The capital forecast, maintained and periodically updated in CBS, covers a minimum six-year (72 month) planning horizon including the year to date actuals (Jan-March 2012) and the current year's forecast (April-Dec 2012), often referred to as the bridge year (see diagram below). The company uses the comparison of capital budgets to actual performance to help determine if projects are on schedule and are consistent with on-going business planning requirements. **Thus providing good estimated in-service dates or closing patterns for projects is important and drives the change in rate base and impacts the income statement forecast of AFUDC and depreciation expense. In summary, your capital forecast must be verified against the "Checklist for Capital Forecasts", which includes the following and more:**

- Capital expenditures separated into Construction Work in Progress (CWIP) , Removal Work In Progress (RWIP), and Customer Contributions in Aid of Construction (CIAC) if applicable object accounts
- Estimated in-service date or closing pattern aligned with the expenditure pattern
- Forecast for all parent work orders including those with a CWIP/RWIP balance after March 2012 accounting close,

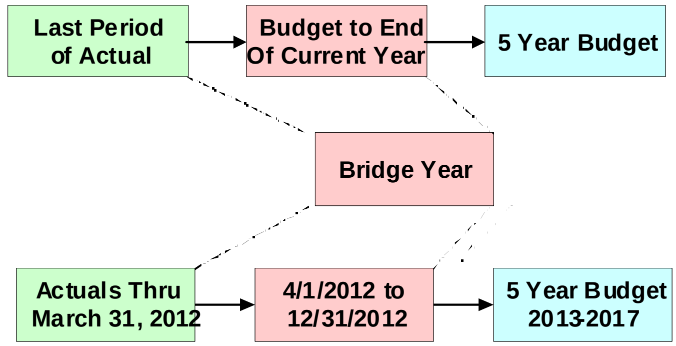
What is a Capital Budget?

The capital budget is a combination of: CWIP expenditures (spend to install an asset); RWIP expenditures (spend to remove an asset); and estimated in-service dates (or closing patterns), to arrive at the budgeted plant in-service (a major component of rate base). The budgeted plant in-service and related items (depreciation, AFUDC, etc) is an important input to cost of service studies used to support rate filings before various Commissions.

What is a Bridge Year?

The bridge year information is used to compute the beginning plant balances for the 2013 budget. Finally, capital forecasts support the estimation of the cash flow needs for the company into the future. All of these reasons make it important that the capital budget accurately reflect the expenditures and expected in-service dates for <u>the bridge year and upcoming budget</u> period and is consistent with the requirements stated below

Bridge Year



General Guidance

Capital budgets must meet the capitalization criteria and minimum levels of detail. In addition, proper documentation must include a description of each project and a financial explanation as to how expenditures were derived. Describe the benefits of the capital project, such as: productivity, process efficiency, reliability, safety, required due to law or covenant, etc. When writing descriptions and justifications for capital projects, please be as precise as possible. Refer to the *Capital Asset Accounting Policy - Capital Budget Principles* for additional information.

Support for routine projects requires a five-year expenditure and in-service history, or the assumptions used to develop the expenditure pattern and closing pattern. Closing patterns are developed to move dollars out of CWIP to plant in-service based upon their historic construction period for routines or completed phase of construction for non-routine projects. Construction completed in phases (more than one estimated in-service date per parent work order) has a closing pattern called "percent of work complete". Contact Capital Asset Accounting (CAA) if you need a project set up to close to plant in-service in phases for the budget. See the CAA Business Area Liaison list for contacts.

Capital budgeting data requirements for all projects are six years (i.e., 2012-2017) of monthly expenditures beginning with the remaining months of the forecast for the current bridge year (i.e., April to December 2012, assuming actual expenditures through March 2012), estimated in-service dates and closing patterns, where applicable. To capture total project expenditures, current forecasts must be reviewed and updated. In addition, actual CWIP balances need to be reviewed for estimated in-service dates, as well as any additional expenditure. Please see the "Requirements" section for more information.

Assumptions

Corporate Escalation Rates

Business areas, when preparing their six-year budgets (i.e., 2012-2017) of capital data, should NOT use "current year" dollars, but should use an appropriate escalation factor to cover costs for inflation. For general inflation increase estimates refer to the *Corporate Escalation Rates* published on the Corporate Budgeting Home Page. Other economic drivers may exist that require the use of more specific escalation factors for certain expenditures, such as nuclear fuel, steel or copper or long lead-time items such as power transformers. The support for all factors used should be well documented. Contact Supply Chain Sourcing for relevant pricing information on many key categories.

Capital PC Refresh and IT Asset Management

Efficient use of Personal Computing assets enables Xcel Energy to leverage volume purchases, minimize support costs through product standardization, promote compatibility between IT assets and Xcel Energy's computing environment, monitor compliance with software licensing/data security, and maximize return on investment by carefully managing the lifecycle and use of these assets. . For additional information about IT management standards please refer to the following link: ***Business Systems Standard***

IT Asset Management will determine an appropriate schedule for refreshing personal computers (PCs). At the start of the year, a list of the PCs to be refreshed during the year will be generated with a tentative schedule. The schedule will be maintained and updated during the course of the year.

Requirements for PCs outside of the refresh schedule will be closely scrutinized. The following justifications are acceptable for securing a new workstation: 1) hiring of a new employee, 2) PC lost or stolen, and 3) malfunctioning PC that is not repairable. Please refer to the section below for requesting and budgeting new PCs that are not included in the refresh project.

Budgeting for New IT Initiatives

All IT capital project budgets are budgeted by Business Systems and should not be part of the business areas' budgets. This includes software implementations, as well as hardware capital purchases for PCs, LANs and printers that meet the capital guidelines. Business areas should not budget for software/hardware projects. If you have any questions, contact Diane Prentis at 612-330-5744.

If you have a new IT initiative, such as a new application system, new support or a non-standard purchase, please contact Business Systems area directly to discuss your initiative. The contact list can be found under the following link Business Systems Contacts. This information is important so that Business Systems can budget and plan accordingly.

Efficient use of Personal Computing assets enables Xcel Energy to leverage volume purchases, minimize support costs through product standardization, promote compatibility between IT assets and Xcel Energy's computing environment, monitor compliance with software licensing/data security, and maximize return on investment by carefully managing the lifecycle and use of these assets. . For additional information about IT management standards please refer to the following link: ***Business Systems Standard***

Overheads – E&S and A&G

CAA does not add Engineering and Supervision (E&S) and Administrative and General (A&G) overheads to the expenditure stream for project budgets or forecasts as part of its budget processing. These project overheads are assumed to be ***included*** in the capital expenditure forecast provided. Each business area should assess the potential impact to their projects, especially for E&S charges for their large projects, and budget accordingly.

Allowance for Funds Used During Construction (AFUDC)

Capital expenditures input by the business areas should **not** include AFUDC, which is calculated outside of CBS by CAA. CAA manages the actual accounting for AFUDC as well as the AFUDC associated with forecasted capital expenditures.

Environmental

Environmental capital expenditures associated with air, water and waste remediation should be budgeted in accordance with the *Environmental Budget Guidelines* published on the Corporate Budgeting Home Page. A clear distinction is made in the guidelines and Capitalization Policy identifying environmental charges that can be capitalized verses those that are required to be expensed.

Demand Side Management

Costs associated with Demand Side Management (DSM) or Conservation Investment Program (CIP) are not included in the capital forecast unless the resulting transaction involves a capital asset. Most DSM or CIP assets are accounted for as regulatory assets. These costs should be budgeted with a deferred parent work order, which is different than a capital parent work order. There are specific rules for these deferred work orders and they require Corporate Accounting approval.

Capital Help

If you need assistance from CAA, contact the CAA Hotline at 612-330-6490.

In addition, please refer to the *Capital Budget/Forecast-Parent Checklist* on the CAA website. For the budget and every month a capital forecast is reviewed and modified; this checklist should be used with each parent project to assure that there is no missing information in the data provided. This checklist will be used as a basis to measure how accurate and complete the capital budget/forecast you provide is.

Requirements

The total of capital expenditures for each of the next six years is significant and accordingly, we must prepare detailed budgets with transparency on where these amounts are being planned. The information below explains how to prepare your budgets to facilitate accurate budgeting and forecasting. CAA maintains the accounting policies and procedures and should be consulted, as needed, to insure proper accounting.

The primary balance sheet items that are impacted by **capital expenditures and estimated in-service dates or closing patterns** are Construction Work in Progress (CWIP), Plant In-Service, Accumulated Depreciation and Plant-Related Accumulated Deferred Income Taxes. Income statement influences include AFUDC and depreciation expense. The capital expenditures and dates are gathered across the business areas using CBS, Tamcast and Workbook and passed along to PowerPlant for the calculations of plant additions, book and tax depreciation, equity and debt AFUDC, and deferred income tax expense. The accurate forecasting of these amounts requires that the capital data (both spend and dates) be gathered and input into CBS, Tamcast or Workbook in accordance with the designed financial system and business process requirements.

Capital Expenditures

Accurate Monthly Expenditure Pattern - One of the critical responsibilities of the Financial Operations organization is to ensure that sufficient cash is available to cover cash requirements. To accomplish this, the company must be able to derive meaningful cash flow forecasts from the financial budget and its monthly forecasts. Even though expenditure is booked to capital; a dollar is spent and that dollar must be available to be paid out. The Financial Operations organization needs the pattern of expenditures from the budget or the forecast to assure that funds are available and consistent with long-term and short-term financing plans.

The cash flows or expenditures are provided when input into CBS, Tamcast or Workbook and these expenditures can be patterned or levelized, but should be representative of what one expects the monthly pattern of actual expenditures to be. This is important because the Company will plan its cash needs based on the expected cash outflows for construction. A large expenditure that was not anticipated could cause the company to incur higher than necessary carrying charges to obtain the funds than it may have if it could have planned for the large outflow of cash.

Separate Install Expenditures from Removal Expenditures - Capital expenditures cover both the capital dollars spent to install and remove capital assets. Expenditures associated with removal, as part of an asset retirement, should be budgeted as RWIP not CWIP. The importance of this is threefold:

1. RWIP does not accumulate AFUDC, whereas CWIP does,
2. RWIP is considered part of rate base for rate making when it is spent; CWIP is not part of rate base until it becomes an addition to plant in-service.
3. Estimated removal expense has been recovered from rate payers through the depreciation expense in the past, whereas CWIP will be recovered through depreciation expense in the future

If a project includes removing an existing asset before a new one is installed those removal expenditures should be budgeted as such. An estimate can be used to split the project expenditures and the removal estimate is entered into CBS, Tamcast or Workbook by using the RWIP JDE object accounts 740000-743350. Removal and installation expenditures can be tracked through the same parent work order. If significant salvage transactions are anticipated, they should be considered. It may be desirable to budget or forecast removal net of any salvage.

Alignment of Estimated In-Service Dates

Accurate estimated in-service dates are **critical** to ensuring that the financial systems (PowerPlant and CFM) know when to stop AFUDC, when to move the constructed asset from CWIP to plant in-service, and when to start book and tax depreciation. Also, for most projects, they are included in rate cases (rate base) when they are forecasted to move from CWIP to plant in-service.

For specific capital projects, the estimated in-service date must align with the expenditure pattern.

The in-service date is when commercial operation begins, such as when the line is energized or main pressurized. If a project has two or more phases of construction with different in-service dates, contact one of the CAA Business Area liaisons for assistance to set up a special closing pattern, called percent of work complete (see "Percent of work complete" section for more information).

The estimated in-service date is not the same as the estimated complete date. Typically, there are trailing expenditures, such as restoration, after the in-service date until the complete date. Each time a user updates their expenditures forecast, estimated in-service dates also need to be re-evaluated. It is also important to reevaluate and revise estimated in-service dates for projects expected to go in-service in the bridge year, 2012. The bridge year information computes the beginning plant in-service balances for the 2013 Budget. Inaccurate estimated in-service dates can negatively impact the forecast accuracy of depreciation expense, AFUDC, and plant in-service.

The general rules for the forecast expenditures alignment with dates:

- estimated in-service date **should not** be past the last month of the forecasted expenditures,
- there should be **no more than three months** (four month for Nuclear operations) of expenditures past the estimated in-service date (for large projects, the spend may go beyond three months),
- the estimated complete date cannot be before the estimated in-service date,
- the estimated complete date should be at the end of the last expenditure.

Routine projects are treated as short-term construction projects that are generally ready for service the month of the construction expenditures. For example, construction expenditures for routine projects like battery replacements at substations or general plant equipment forecasted in May will go into service in May for budget or forecast purposes

For routine projects closing pattern must be aligned with the expenditures pattern. There are several closing patterns to choose from for routine projects that in-service a certain portion of the CWIP or RWIP balance (built from beginning actual CWIP/RWIP balance plus forecast spend for a project plus AFUDC on the CWIP portion) based on the number of months of construction or other percent.

Closing patterns are developed to move dollars out of CWIP to plant in-service based upon the estimated construction period. For these kinds of routines the rules set forth by closing patterns are used to move dollars from CWIP to plant in-service **until** the estimated in-service date is reached, then that is used to move dollars from CWIP to plant in-service for any additional expenditures. Please refer to the illustration below that shows the roll forward example of Routine project with CWIP activity:

Routine Parent work order with Est In-service Date 12/31/2013 and Closing Pattern "4 Mo Construct (40%)"

			Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
a		CWIP Beginning Balance	1,000,000	724,800	589,080	446,448	-	-
b		CWIP Forecasted Expenditures	200,000	250,000	150,000	300,000	50,000	25,000
c		AFUDC	8,000	7,000	5,000	5,000		
d	(a+b+c)	CWIP Balance Available to Close	1,208,000	981,800	744,080	751,448	50,000	25,000
e	(d x g)	CWIP Plant Additions (Closings)	(483,200)	(392,720)	(297,632)	(751,448)	(50,000)	(25,000)
f	(d + e)	CWIP Ending Balance	724,800	589,080	446,448	-	-	-
g		Closing Pattern (%)	40%	40%	40%	100%	100%	100%

Closing patterns are also used to move Removal expenditures (RWIP) to accumulated depreciation reserve (these don't close to plant in-service, but impact net plant) based upon the estimated construction period. The rules set forth by closing patterns are used to move dollars from RWIP to reserve **until** the estimated completion date is reached, then that is used to move dollars from RWIP to reserve for any additional expenditures

Routine Parent work order with Est Completion Date 02/1/2014 and Closing Pattern "4 Mo Construct (40%)"

			Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
a		RWIP Beginning Balance	1,000,000	720,000	582,000	439,200	443,520	296,112
b		RWIP Forecasted Expenditures	200,000	250,000	150,000	300,000	50,000	25,000
c		AFUDC	-	-	-	-	-	-
d	(a+b+c)	RWIP Balance Available to Close	1,200,000	970,000	732,000	739,200	493,520	321,112
e	(d x g)	Depr Reserve Additions (Closings)	(480,000)	(388,000)	(292,800)	(295,680)	(197,408)	(321,112)
f	(d + e)	RWIP Ending Balance	720,000	582,000	439,200	443,520	296,112	-
g		Closing Pattern (%)	40%	40%	40%	40%	40%	100%

If you are forecasting a routine project for the entire forecast period (2012-2017) you may want to set the estimated in-service date past the forecast period, to avoid CWIP/RWIP balance to close 100 percent to plant within the forecast period; and it is suggested to set it no more than 5 years out from the last forecast period (ie, 2022 for this budget). Please note that the estimated complete date cannot be more than 30 years from the estimated start date, and the estimated in-service date cannot be past the estimated complete date.

Percent of Work Complete – For the parent work orders with multiple phases of construction, a single specific estimated in-service date will not work. Either a percent or dollar amount should be identified for specific periods to move CWIP or RWIP to Plant In-service or Accumulated Depreciation Reserve, respectively. The last phase of the project will use the estimated in-service date to close the remaining CWIP and estimated completion date the remaining RWIP. For those parent work orders that have CWIP and RWIP forecasted expenditures and have percent work complete closing patterns, the RWIP portion can be set up to close on the estimated complete date, the same dates as the percent set up for the CWIP portion, or a different pattern altogether. CAA will need to work with you on setting these up.

If parents are set up for each phase of the project related to the estimated in-service date one could avoid using percentage of work completed closing method.

1. ***Other-*** Do not budget or forecast spend on parent projects that have a status of cancelled, posted to CPR, completed, in-service, or unitized. If you do use these parents to forecast expenditures, the actual in-service date will be used to move dollars from CWIP to Plant in-service in the forecast, which means forecasted spend will be in-serviced in the same month as the spend occurs, since the actual in-service date will be in the past.

Current Year Projects and Projects with CWIP Balances

All projects with actual CWIP balances must be reviewed for both spend and estimated dates. If the estimated in-service is in the past, the project must be evaluated for either additional expenditures to be budgeted and estimated in-service date to be changed or the asset is used and useful and children work orders need to be in-serviced. Make every effort to have work orders in-serviced as soon as they are used and useful assets. It is important that the starting month of forecast has an accurate starting CWIP balance. Also, all open projects must be evaluated for expenditures for 2012 and beyond and the estimated in-service date must also be reviewed and updated if necessary.

Asset Retirements

Asset retirement is the removal or abandonment of an asset (or part of an asset if it meets the capitalization policy) from the field, and the removal of said asset from the Capital Asset Accounting Continuing Property Record. Because forecasted asset retirements are not recorded in any of the budgeting systems, planned (forecasted) large asset retirements need to be communicated to CAA during the budget process timeframe. It is important for both depreciation expense and tax depreciation to identify the retirements in the forecast.

The routine Transmission and Distribution mass property retirements are forecasted based on historical data; however if there are any known large and unusual planned retirements, they need to be communicated to your CAA liaison in advance. See the CAA Liaison contacts for T&D at the end of the Capital Budgeting section

The Production asset retirements, in the budget, are processed based on planned retirements of individual large property groups (a whole property unit system or some major component of such system) or production plant. If there are plans to retire large production assets or any generating plants that may go off-line and become fully retired in the 2012-2017 cycle please provide plant name and projected date of decommissioning to Dave Amans in CAA (for contact information please refer to the CAA Liaison section at the end of this Capital Budgeting Instructions). The information from previous forecast is maintained by CAA and provided back to BA for the updates every budget/forecast cycle. CAA will then work with you to determine the specific asset(s) to retire in the forecast once information is gathered.

Legal Expenditures

Legal expenditures related to deferred or capital projects may warrant inclusion in the total expenditure of the project and are to be budgeted within the respective business area's deferred or capital budget. Business areas having capital projects or deferred expenditures, which may include legal expenses, must contact Legal Services. Legal Services will provide the estimated budget for these projects to the business areas and will monitor legal expenditures associated with the project. Contact Deb Meuwissen at 612-215-4545 or Kimberly Hardy at 303-294-2010 if you have any questions.

Capitalization Policy

Every parent work order, upon initiation, is validated for consistency with the Capitalization Policy (i.e., accounting guidance applicable for actual book activity should be applied to budget and forecast data). This is true for every child work order as well. Occasionally, a project changes scope from the time it was budgeted to the time the actual work begins. If the actual work no longer meets the criteria for capitalization, the work cannot be capitalized even though the dollars reside in the capital budget. To avoid surprises between the budget and actual project expenditures, it is imperative that detail information be provided **before** initiation of the parent work order so that CAA can do the Capitalization Policy test quickly. **Please note that CAA policy is to validate projects within 3 days of receipt. During the busy budget season, CAA may need the full 3 days to complete validation, so please plan accordingly. Likewise, if hundreds of projects are sent at once to CAA to validate, turn around time may be longer.**

Level of Detail

All parent work orders budgeted within CBS and PowerPlant must identify the proper Utility (i.e., electric, gas) and functional class (i.e., steam production, transmission) consistent with the FERC Uniform System of Accounts. The *Capital Expenditure Budget Requirements Matrix* included in the Appendices, summarizes the level of detail required. This level of detail is achieved in the budget by choosing the appropriate **Funding Project Type** when setting up your parent work order. This level of detail is required to identify depreciable from non-depreciable plant. It also captures plant accounts, which use different depreciation rates. This information must be budgeted for each operating company, as the approved depreciation rates vary by company.

The Regulatory department uses plant information for establishing electric and gas utility rates. There is a minimum level of detail at which projects cannot be further combined. All business areas must follow these requirements. For example, transmission substation work cannot be combined with the transmission line work. The matrix includes a listing of the applicable 300 level FERC accounts where such budgeted capital expenditures are typically closed to plant in-service. Also, see below for the detail required for parent work orders with special rate treatment.

***Transmission Serving Generation or Distribution Serving Generation* –** For projects with interconnection facilities and network upgrades associated with generation facilities, specific funding project types should be used. **Please note that there are new funding project types for transmission serving generation work** (distribution serving generation can be set up upon business need) and this distinction must be made when setting up your projects for budgeting. This is important for ratemaking purposes. The distinction is made based upon the primary purpose for installing the transmission or distribution assets, rather than budget ownership. The budgeting guideline on this topic is included in the Appendices. Also the Transmission Interconnection & Network Glossary and Transmission Serving Generation Ownership Scenarios documents posted on the Capital Asset Accounting web page (Transmission Serving Generation).

Parent Project Naming Conventions and Grandparent Summarization

Capital budgets and forecasts are used in rate case filings. It is important to consider how you name your project. Naming conventions may be used by your business area to facilitate easier identification of related projects, for instance, those related to a particular generating plant. Also, words that are descriptive help in understanding what the project is for. In addition, upon setting up your project you must choose a grandparent, which is another means to summarize types of projects. The grandparents are used to summarize and present CWIP and RWIP data in rate case schedules and testimony and should help explain the type of project. Projects related to each other, even if in different business segments, should be budgeted, have the same grandparent and dates should be in-sync. If you think you need a new grandparent, that is not currently in the CBS dropdown list, please choose the “Need New Grandparent” grandparent and then call your business area financial representative to discuss. The business area financial representative should then call the CAA liaison for the business area to discuss.

Separately Budget Capital Projects with Special Rate Treatment

Estimated in-service dates and expenditures affect the budgeted or actual revenue collected for rate rider projects as well as projects having special rate treatment (e.g., PSCo Transmission Cost Adjustment (TCA) also called Senate Bill 100). These projects are considered “Projects of Interest” and require prioritized reviews and updates. Therefore, CBS, Tamcast or Workbook should be updated with the most accurate estimates for the budget as well as monthly forecast updates, for both expenditures and estimated in-service dates. Each project must have separate parent work order numbers. CAA uses a specific rate code on parent work orders to assure proper processing through rate case preparation. The specific rate codes are provided by and approved by the rate areas. **Please contact the Rate Area concerning all projects that qualify for special rate treatment.**

Any capital expenditures unrelated to the project (i.e., not subject to special rate treatment) must be budgeted to a separate parent work order. Thus, parent work orders requiring special rate treatment should have only the capital expenditures that are included in the approved regulatory orders or legislative mandates. Budget any removal expenditures associated with these projects in RWIP JDE object accounts 740000-743350, since removal expenditures do not qualify for any AFUDC calculations.

Type of Charges Incurred

Capital expenditures primarily include employee labor and benefits, contract labor, materials and other direct expenditures. AFUDC charges are calculated outside of CBS and should not be included as part of a users budgeted capital expenditures. AFUDC is added and becomes a component of the total construction charges included with the parent and child work orders within the Company's financial systems.

Reason Codes

Within the CBS system, the Company has established reason codes, which provide information about each parent work order that is used for internal reporting purposes to better understand and track expenditures. For example, the reason code, replace/refurbish should be applied to projects related to replacing worn-out or damaged or degraded equipment. These capital expenditures can then be distinguished from investments to serve new customers. While this information does not impact the forecast balance sheet or income statement, it provides useful information for management and is required. For more information on reason codes please see *Reason Code Definitions* published on the Corporate Budgeting Home Page.

Customer Contributions in Aid of Construction (CIAC), Reimbursements, and Customer Advances

Non-refundable contributions in aid of construction (non-refundable CIAC, not customer advance or refundable CIAC) and other capital reimbursements from third parties are a common component of certain capital expenditures within the Delivery and Transmission business areas.

Non-refundable CIAC's typically received for additional facilities installed for customers should be included in the capital expenditure forecast where applicable and can be supported with historical trends. Each business area needs to budget for non-refundable CIAC using JDE object accounts 733400-733460. Refundable CIAC or customer advances are not forecasted within CBS.

Customer reimbursements for relocating facilities to accommodate customers (other than Department of Transportation (DOT) customers), should be budgeted using object account 743150. For DOT customers, use object account 743160 to budget the credit.

Joint Ownership Share

Xcel Energy has joint ownership capital projects, where Xcel Energy pays the full construction expenditures, then is reimbursed by the third party or joint owner, such as Comanche 3, Sherco 3, and Transmission CapX2020. With joint ownership projects, it is recommended to budget capital expenditures gross, the full amount, then record a credit to the appropriate joint ownership object account CWIP Joint Ownership 733340-733346 or RWIP Joint Ownership 743150-743160.

Capital Asset Accounting Business Area Liaisons

Budget Organization	CAA Liaison	Phone
Corporate Services	David Adams	303-294-2094
Transmission	Ray Hetherington	612-330-5565
Distribution	Becky Dean	303-294-2395
Energy Supply NSPM	Carol Callahan	612-330-7659
Energy Supply NSPW	Dave Amans	715-737-2495
Energy Supply PSCo	Kris Jenson	612-330-5583
Energy Supply SPS	Denise LeGault	303-294-2093
Nuclear Generation	Jake Miller	612-330-1959

Appendices

JDE Guidance

JDE Subledger Field

In order to charge out all costs, a subledger field must be entered on all budget lines using a Service Company JDE business unit. Since no JDE business unit can charge the Service Company, the subledger cannot be another Service Company JDE business unit.

There are no construction projects for the Service Company. For a shared asset (an asset used by more than one legal entity, for example 1800 Larimer building), you must contact Capital Asset Accounting and Grover Mills at 303-294-2516 before setting up the project, as accounting for shared assets is a manual process.

For all operating company JDE business units, entering a subledger may not be required. The subledger must not be a Service Company JDE business unit. If a subledger is entered, this represents a cross-charge to the specified O&M or capital work order or JDE business unit within the same legal entity or to another legal entity. All capital projects require the use of an 8-digit subledger. If a subledger is entered, a subledger type of W must be entered.

For more information on JDE account coding, see *JD Edwards Training*.

JDE Subsidiary Field

Do not enter subsidiary values 97, 98 or 99 when budgeting or recording actuals in expense object accounts. These subsidiaries are automatically generated in JDE during the service billing process to identify incoming, outgoing or allocated indirect charges. For budget data this is completed within ALS. For the legal entity view and business area reporting, you can tell if charges received were incoming from or outgoing to another company or department, or indirectly allocated from the Service Company by the subsidiary field. Transactions that are **direct charged** (not allocated) from one department or company to another have a JDE subsidiary of 97 or 99 in the JDE account string. Transactions that are **indirectly allocated** from the Service Company have a JDE subsidiary of 98 in the JDE account string. The subsidiaries are automatically added to the account string, so **do not enter subsidiaries when deriving income statement account numbers**. Subsidiary values on actual balance sheet accounts provide additional account information such as location (city, state, etc.).

Incoming charges – Subsidiary 97 - Your specific JDE business unit was entered into the subledger field by another JDE business unit.
Outgoing charges – Subsidiary 99 – You entered another JDE business unit in the subledger field in order to bill the charges to that business unit.
Indirect charges – Subsidiary 98 – Allocated charges from the Service Company

Example of Direct Charge from Operating Company to Operating Company:

	Company	Business Unit	Object Acct	Subsidiary	Subledger	Amount
Original	NSPM	801598-NSPM	714000		803599-PSCo	700
Outgoing	NSPM	801598	714000	99	803599	-700
Incoming	PSCo	803599	714000	97	801598	700

Example of Allocated Charge from Service Company Using a 3-Digit Allocation Code:

	Company	Business Unit	Object Acct	Subsidiary	Subledger	Amount
Original	XS	601000	711142		121	1,000
Allocation	XS	601000	711142		121	-1,000
Allocation	XS	601000	711142	98	999232-PSCo	377.40
Allocation	XS	601000	711142	98	999233-SPS	140.70
Allocation	XS	601000	711142	98	699109-PSR	.70
Allocation	XS	601000	711142	98	999011-1480	.70

Allocation	XS	601000	711142	98	999230-NSPM	414.10
Allocation	XS	601000	711142	98	999231-NSPW	66.30
Allocation	XS	601000	711142	98	498725-Reddy	.10
Outgoing	XS	50	Revenue			-1,000
Indirect Chg	PSCo	999232	711142	98	601000	377.40
Indirect Chg	SPS	999233	711142	98	601000	140.70
Indirect Chg	PSR	699109	711142	98	601000	.70
Indirect Chg	1480	999011	711142	98	601000	.70
Indirect Chg	NSPM	999230	711142	98	601000	414.10
Indirect Chg	NSPW	999231	711142	98	601000	66.30
Indirect Chg	Reddy	498725	711142	98	601000	.10

Note: These examples exclude inter-company receivable/payable entries that are also automatically generated by JDE during service billing.

FERC, Utility and State Jurisdiction Accounting

Each business area is responsible for the appropriate utility (electric, gas, thermal and non-utility) and FERC designation on their business areas' budgeted O&M dollars. The JDE business unit and object account determine the utility and FERC account. Each JDE business unit and object has category codes attached to it that determine which utility and FERC account the account string translates to. Here is a brief description of some of the main category codes:

Utility Category Codes
Account category code 20 – electric, gas, thermal, non-utility and common (if this field is populated it overrides BU category code 3)
BU category code 3 – electric, gas, thermal, non-utility and common

FERC Category Codes
Account category code 21 – FERC account (if this field is populated it overrides BU category code 21)
BU category code 21 – FERC account

Other Category Codes
BU category code 4 – A&G, operating, maintenance, etc.
BU category code 5 – functional class such as distribution, production, sales, gas storage, etc.
BU category code 6 – location code which helps determine the applicable state jurisdiction

For any costs directly attributed to a specific jurisdiction, ensure the location code (BU category code 6) on the JDE business unit is correct (if there is no subledger). If there is a subledger, verify the location code on the subledger is correct.

For additional information on translating JDE account strings to FERC account and utility, please see the document titled *JD Edwards Regulatory Ledger Training* on the Regulatory Accounting Training webpage.

Capital Expenditure Budget Requirements Matrix

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
Electric Utility			
Steam Production	◦ Land and land rights including water rights	◦ Land and land rights including water rights	◦ 310.0 – Land ◦ 310.1 – Land Rights
	◦ Total assets by facility except for a few that are separated by unit due to different depreciation rates, such as Sherco and Comanche	◦ Depreciable assets by facility, except where individual units are jointly-owned by third parties or use different depreciation rates (Sherco 3 and Comanche 3)	◦ 311 – Structures & Improvements ◦ 312 – Boiler Plant Equipment ◦ 314 – Turbogenerator Unit ◦ 315 – Accessory Electric Equipment ◦ 316 – Miscellaneous Power Plant Equipment
Nuclear Production	◦ Total assets by facility	◦ Land and land rights	◦ 320.0 – Land ◦ 320.1 – Land Rights
		◦ Depreciable assets by facility	◦ 321 – Structures & Improvements ◦ 322 – Reactor Plant Equipment ◦ 323 – Turbogenerator Unit ◦ 324 – Accessory Electric Equipment ◦ 325 – Miscellaneous Power Plant Equipment
Nuclear Fuel	◦ Total assets by facility	◦ Total assets by facility	◦ 120.2 – Nuclear Fuel Materials and Assemblies – Stock ◦ 120.3 – Nuclear Fuel Assemblies in Reactor ◦ 120.4 – Spent Nuclear Fuel
Hydro Production	◦ Total assets with no facility separation	◦ Land and land rights	◦ 330.0 – Land ◦ 330.1 – Land Rights

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
		◦ Depreciable assets by facility	◦ 331 – Structures & Improvements ◦ 332 – Reservoirs, Dams & Waterways ◦ 333 – Waterwheels, Turbines & Generators ◦ 334 – Accessory Electric Equipment ◦ 335 – Miscellaneous Power Plant Equipment ◦ 336 – Roads, Railroads & Bridges
Other Production	◦ Land and land rights	◦ Land and land rights	◦ 340.0 – Land, ◦ 340.1 – Land Rights
	◦ Depreciable assets by facility	◦ Depreciable assets by facility	◦ 341 – Structures & Improvements ◦ 342 – Fuel Holders, Producers & Accessories ◦ 343 – Prime Movers ◦ 344 –Generators ◦ 345 – Accessory Electric Equipment ◦ 346 – Miscellaneous Power Plant Equipment
Transmission	◦ Land and easements	◦ Land ◦ Easements	◦ 350 – Land ◦ 350 – Land Rights
	◦ Substations	◦ Substations	◦ 352 – Structures & Improvements ◦ 353 – Station Equipment
	◦ Substations	◦ Substations - Transmission Serving Generation	◦ 352 and 353
	◦ Lines	◦ Lines	◦ 354 – Towers & Fixtures ◦ 355 – Poles & Fixtures ◦ 356 – Overhead Conductor & Devices ◦ 357 – Underground Conduit ◦ 358 – Underground Conductor & Devices ◦ 359 – Roads & Trails
	◦ Lines	◦ Lines – Transmission Serving Generation	◦ 354 - 358
Distribution	◦ Land and easements	◦ Land	◦ 360 – Land

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
(By state)		◦ Easements	◦ 360 – Land Rights
	◦ Substations	◦ Substations	◦ 361 – Structures & Improvements
			◦ 362 – Station Equipment
	◦ Lines	◦ Lines	◦ 364 – Towers & Fixtures
			◦ 365 – Overhead Conductor & Devices
			◦ 366 – Underground Conduit
			◦ 367 – Underground Conductor & Devices
	◦ Other	◦ Other	◦ 368 – Line Transformers
			◦ 369 – Services
			◦ 370 – Meters
			◦ 371 – Installs on Customer's Premises
		◦ Street Lighting	◦ 373 – Street Lighting & Signal Systems
General Property	◦ Non-depreciable	◦ Intangibles	◦ 301 – Organizational Costs
			◦ 302 – Franchises & Consents
		◦ Land	◦ 389 – Land
		◦ Easements	◦ 389 – Land Rights
	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ Buildings	◦ Buildings	◦ 390 – Structures & Improvements
	◦ Transportation Equipment	◦ Transportation Equipment	◦ 392 – Transportation Equipment
			◦ 396 – Power Operated Equipment
	◦ General Equipment (Includes communication for PSCo and SPS)	◦ Furniture & Equipment	◦ 391 – Office Furniture & Equipment
		◦ Network Equipment	◦ 391 – Office Furniture & Equipment
		◦ Tools & Equipment	◦ 393 – Stores Equipment
			◦ 394 – Tools, Shop & Garage Equipment
			◦ 395 – Laboratory Equipment
			◦ 398 – Miscellaneous Equipment
	◦ Communication Equipment (for the NSPM	◦ Communication Equipment	◦ 397 – Communication Equipment

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
	and NSPW only)	◦ Telecommunication Equipment	◦ 397 – Telecommunication Equipment
Gas Utility			
Manufactured Production	◦ Total Assets	◦ Land ◦ Depreciable assets	◦ 304 – Land ◦ 305 – Structures & Improvements ◦ 311 – Liquefied Petroleum Gas Equipment ◦ 320 – Other Equipment
Gathering Production	◦ Total Assets (PSCo Only)	◦ Easements ◦ Depreciable assets	◦ 325.4 –Rights-of-way ◦ 327 – Field Compressor Station Structures ◦ 328 – Field Measuring & Regulating Station Structures ◦ 329 – Other Structures ◦ 332 – Field Lines ◦ 333 – Field Compressor Station Equipment ◦ 334 – Field Measuring & Regulating Station Equipment
Extraction Production	◦ Total Assets (PSCo Only)	◦ Land and easements ◦ Depreciable assets	◦ 340.1 – Land, ◦ 340.2 – Land Rights ◦ 341 – Structures & Improvements ◦ 342 – Extraction & Refining Equipment ◦ 343 – Pipe Lines ◦ 344 – Extracted Product Storage Equipment ◦ 345 – Compressor Equipment ◦ 346 – Gas Measuring & Regulating Equipment ◦ 347 – Other Equipment
Underground Storage	◦ Total Assets	◦ Land and easements ◦ Depreciable assets	◦ 350.1 – Land, ◦ 350.2 –Rights-of-way ◦ 352.1 – Storage

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
			Leasehold and Rights ◦ 352.2 – Reservoirs ◦ 352.3 – Non-recoverable Natural Gas ◦ 353 – Lines ◦ 354 – Compressor Station Equipment ◦ 355 – Measuring & Regulating Equipment ◦ 356 – Purification Equipment
Other Storage	◦ Total Assets	◦ Land and easements ◦ Depreciable assets	◦ 360.1 – Land ◦ 360.2 – Land Rights ◦ 361 – Structures & Improvements ◦ 362 – Gas Holders ◦ 363 – Purification Equipment ◦ 363.1 – Liquefaction Equipment ◦ 363.2 – Vaporizing Equipment ◦ 363.3 – Compressor Equipment ◦ 363.4 – Measuring & Regulating Equipment ◦ 363.5 – Other Equipment
Transmission (By state)	◦ Land and easements ◦ Depreciable Assets	◦ Land ◦ Easements ◦ Depreciable assets	◦ 365.1 – Land ◦ 365.1 – Land Rights, ◦ 365.2 – Rights of Way ◦ 366 – Structures & Improvements ◦ 367 – Mains ◦ 368 – Compressor Station Equipment ◦ 369 – Measuring & Regulating Station Equipment ◦ 370 – Communication Equipment ◦ 371 – Other Equipment
Distribution (By state)	◦ Land and easements	◦ Land ◦ Easements	◦ 374 – Land ◦ 374 – Land Rights

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
	◦ Mains, TBS, Meters and Regulators	◦ Mains and TBS; includes services	◦ 375 – Structures & Improvements ◦ 376 – Mains ◦ 380 – Services
		◦ Meters and Regulators	◦ 381 – Meters (includes 382 – Meter Installations, 383 – Regulators, and 384 – Regulator Installations) ◦ 387 – Other Equipment
General Property	◦ Non-depreciable	◦ Intangibles	◦ 301 – Organizational Costs, ◦ 302 – Franchises & Consents
		◦ Land	◦ 389 – Land
		◦ Easements	◦ 389 – Land Rights
	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ Buildings	◦ Buildings	◦ 390 – Structures & Improvements
	◦ Transportation Equipment	◦ Transportation Equipment	◦ 392 – Transportation Equipment ◦ 396 – Power Operated Equipment
	◦ General Equipment (Includes communication for PSCo only)	◦ Furniture & Equipment	◦ 391 – Office Furniture & Equipment
		◦ Network Equipment	◦ 391 – Office Furniture & Equipment
		◦ Tools & Equipment	◦ 393 – Stores Equipment ◦ 394 – Tools, Shop & Garage Equipment ◦ 395 – Laboratory Equipment ◦ 398 – Miscellaneous Equipment
	◦ Communication Equipment (Includes communication for NSPM and NSPW only)	◦ Communication Equipment	◦ 397 – Communication Equipment
	◦	◦ Telecommunication Equipment	◦ 397 – Telecommunication Equipment
Thermal Utility			
Production	◦ Land	◦ Land	◦ 310 – Land
	◦ Depreciable Assets	◦ Depreciable assets	◦ 311 – Structures &

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
			Improvements ◦ 312 – Boiler Plant Equipment ◦ 315 – Accessory Electric Equipment ◦ 316 – Miscellaneous Power Plant Equipment
Distribution	◦ Depreciable assets	◦ Depreciable assets	◦ 376 – Mains ◦ 378 – Measuring & Regulating Equipment – General ◦ 380 – Services ◦ 381 – Meters ◦ 382 – Meter Installations
General Property	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ General Equipment	◦ Tools & Equipment	◦ 391 – Office Furniture & Equipment ◦ 393 – Stores Equipment ◦ 394 – Tools, Shop & Garage Equipment ◦ 395 – Laboratory Equipment ◦ 398 – Miscellaneous Equipment
Non-Utility			
Production & Other	◦ Non-depreciable assets	◦ Non-depreciable assets	◦ 121 – Non-utility Property
	◦ Depreciable assets	◦ Depreciable assets	◦ 121 – Non-utility Property
Common Utility			
General Property	◦ Intangibles	◦ Intangibles	◦ 301 – Organizational Costs ◦ 302 – Franchises & Consents
		◦ Land	◦ 389 – Land
		◦ Easements	◦ 389 – Land Rights
	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ Buildings	◦ Buildings	◦ 390 – Structures & Improvements
	◦ Transportation Equipment	◦ Transportation Equipment	◦ 392 – Transportation Equipment ◦ 396 – Power Operated

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
			Equipment
	◦ General Equipment	◦ Furniture & Equipment	◦ 391 – Office Furniture & Equipment
		◦ Network Equipment	◦ 391 – Office Furniture & Equipment
		◦ Tools & Equipment	◦ 393 – Stores Equipment
			◦ 394 – Tools, Shop & Garage Equipment
			◦ 398 – Miscellaneous Equipment
	◦ Communication Equipment	◦ Communication Equipment	◦ 397 – Communication Equipment
		◦ Telecommunication Equipment	◦ 397 – Telecommunication Equipment

Transmission/Distribution Serving Generation Budgeting Guideline

Questions to Ask:

What is the primary purpose of a connection to the transmission or distribution network or an upgrade to the network?

If the answer is generation (a.k.a production), then the project should be set up as a Transmission Serving Generation (TSG) project or as a Distribution Serving Generation (DSG) project. The setup of the project function should NOT be determined by who has budget responsibility for the project. The parent project should be set up with the funding project type of Transmission or Distribution (Lines or Subs) Serving Production.

If it is a TSG or DSG project, who has budgetary responsibility for the project?

Budget responsibility does not change the classification of the project as Transmission (or Distribution) Serving Generation.

- **<u>If Energy Supply owns the generation assets</u>**
  Energy Supply should have budget responsibility for the Interconnection project; the project will be classified on the books as a Transmission (or Distribution) asset; and for ratemaking purposes, it will be treated like production plant.

  Any Network Upgrades may be budgeted by either Energy Supply or Transmission (the departments must come to an agreement).

- **<u>If an Independent Power Producer owns the generation assets</u>**
  Transmission has the budget responsibility for the Interconnection project (there will be a Contribution in Aid of Construction paid by the IPP offsetting the capital cost in the budget); the project will be classified on the books as a Transmission (or Distribution) asset; and for ratemaking purposes it will be treated like production plant.

  Any Network Upgrades should be budgeted by Transmission. Again, the IPP will pay a Contribution in Aid of Construction (CIAC).

- **<u>If Energy Supply owns the generation assets, but an Independent Transmission Provider owns the interconnection project</u>**
  Energy Supply should budget the project and will pay a CIAC to the ITP; the project will be classified on the books as a Transmission (or Distribution) asset; and for ratemaking purposes it will be treated like production plant.

  If Network Upgrade assets will be owned by Xcel Energy, then those upgrades may be budgeted by either Energy Supply or Transmission (the departments must come to an agreement).

  If Network Upgrade assets will be owned by the ITP, then those upgrades should be budgeted by Energy Supply (who will pay a CIAC to the ITP).

Glossary of Terms

A&G Capital Overhead. Administrative and General is an overhead that assigns the labor from certain departments that are considered general office functions. The amount is based upon a biennial study that looks at the budgeted labor for these departments and the amount of time they dedicate to capital functions.

ALS. Allocation Ledger System, which processes CBS data using service billing functionality similar to JDE and presents the legal entities' O&M and Capital budgets in an allocated view. Managerial view data is also maintained in ALS for reporting.

AFUDC. Allowance for funds during construction represents the cost of financing or funding a project before it is in its revenue-generating phase. Using a FERC specified formula, AFUDC is calculated and added to the capital project and at the same time is recognized as either income (the equity component) or an offset to interest expense (the debt component). When the project goes into service the capitalized cost of the debt and equity is part of depreciation expense, which is a component of the customer's rate.

Blanket Child Work Orders. The blanket child work orders are a summation of many smaller dollar, high volume capital jobs that are grouped together because of the similar nature of the work, i.e., meters or new business blankets.

Bridge Year. Refers to the current year in which there are some actuals and some forecast months. It is a term used in the capital budgeting process to reference the year that precedes the budget years. The bridge year information is used to compute the beginning plant balances for the first year of the budget, and thus is an important component of the budget.

BTE. Business Technology Executives that are assigned to each business area. Representative names are included in the Budget Instructions in the applicable sections.

Business Area. Refers to the areas within the Company that operate as an organizational unit. Examples are: Transmission; Energy Supply; Distribution; Corporate Services and the Chief Financial Officer. For internal reporting, it is an aggregate of JDE Business Units.

CBS. The CompetiSoft Budgeting System is the corporate input tool used for preparing O&M and Capital budgets.

CFM. The CompetiSoft Forecasting Model is the corporate tool used for financial planning/forecasting.

Child Work Order. This is the work order where the actual jobs costs are accumulated. These are often called just work orders without the prefix "child". The forecasting does not occur at the child work order level.

CIAC. Contribution in Aid of Construction.

Closing Pattern. Developed for forecast purposes to move dollars out of CWIP to plant in-service based upon their historic construction period for routines or completed phase of construction for non-routine projects.

Cost Components. A group of object accounts or categories of costs. Examples include employee expenses, contract labor and consulting costs.

CWIP**.** Construction Work in Progress, The spend to install an asset. The balance represents construction work not yet completed but in process..

Deferred Work Orders**.** Used to capture costs associated with regulatory assets, regulatory liabilities deferred assets and deferred liabilities. For additional information contact Regulatory Accounting.

E&S Overhead**.** Engineering and Supervision is an overhead that is used to allocate indirect costs associated with construction from the engineering departments.

In-Service Date. In general, this is the date upon which the construction project has been turned over from the construction manager to the operations manager. In the financial forecast process, this date is called the estimated in-service date and it triggers moving the dollars from CWIP to plant in-service, AFUDC to stop and book/tax depreciation to start (see *Capital Asset Accounting Policy - Capital Budget Principles*).

JDE Business Unit. JDE Business Unit is a six-digit number that represents the department or department structure. For some departments the capital work is assigned a different JDE Business Unit than the operating work. In PowerPlant, this number is shown in the department field.

Percent of Work Complete. **A c**losing pattern developed for a specific parent project work order that have multiple construction in-service phases. The pattern is developed based on input from the project owner, including the forecasted CWIP balance and the dates of an in-service phase and either the amount to in-service or percent of the CWIP balance to in-service..

RWIP. Removal Work In Progress, the spend to remove an asset. The balance represents removal work not yet completed but in process.

Parent Work Order. A parent work order is the terminology used by the JD Edwards system and is synonymous with the term Funding Project used in the PowerPlant system. It is the level at which the budget/forecast data is gathered and reported. Actual project expenditures for capital work are never recorded to the parent work order, but may be summed up and reported at the parent wok order level. Many child work orders can be grouped under one parent work order.

Routine Parent Work Order. Refers to a capital project that contains ready made or quickly installed capital assets such as transportation equipment, network equipment, distribution meters, line transformers, or substation batteries. Previously these were referred to as blanket parent work orders.

Vacancy Rate. Refers to an annualized attrition rate that is budgeted to account for positions that are open at any point during the year.

Corporate Budget Instructions

2014-2018 O&M Budget and Capital Budget

Revised March 2013

Date: March 1, 2013

From: Amy Stitt, Managing Director, Financial Performance and Planning

Reference: O&M and Capital Budget Instructions

The Financial Budget is a key component of the framework for developing supportable and attainable financial plans by legal entity, utility and jurisdiction. It is used to evaluate actual performance and aids management in making business decisions and monitoring ongoing financial performance for each Operating Company (OpCo) and Xcel Energy (or the Company) consolidated. We must continue to increase the effectiveness of our overall business planning processes to successfully execute our strategic, operational and financial plans within the evolving dynamic environments that we conduct business. Specifically, within the budget process, we have developed some guiding principles to help us on this journey:

- Key assumptions within our strategic, operating and resource plans will drive our annual budget and quarterly forecasts;
- OpCo Presidents have significant decision-making authority for their OpCo and must collaborate with Business Area Leadership in developing each OpCo business plan;
- OpCo Presidents must collaborate together in arranging for services performed by the "shared service" business areas;
- Budget detail should be at the highest level possible that allows each organization to run its business effectively and account for its costs in the proper FERC accounts;
- **Operations and Maintenance budgets (O&M)** will consist of **5 years** of monthly detail;
- O&M forecasts, or updates to the budget, will reflect planned changes with OpCo and business area leadership support; and
- **5-year Capital budgets** are developed and updated between annual budget cycles to accurately and timely reflect any major changes to our capital investment plans.

The attached Corporate Budget Instructions (Budget Instructions), including the budget calendar herein, have been prepared considering these guiding principles and are to be used in preparing the 2014-2018 O&M Budgets and the 2014-2018 Capital Expenditure Budgets, including estimated project in-service dates. The following corporate guidance, and policies and procedures for preparing business area and legal entity budgets help ensure the Company's O&M and Capital budgets are accurate, well documented and consistent with the Company's ongoing business planning.

There are only a couple of significant changes in our budgeting process compared to prior years. Both changes pertain to the use of capital subledgers:

- Beginning this year, we will be using the 99999997 subledger to budget for transportation non-labor capital costs. This is explained in detail on pp. 18 & 19.
- Also new for this year, we will be using the 99999998 subledger to budget for capital labor costs associated with work planned for IT projects. This is explained on pp. 9 & 11.

Other than those changes, expectations for this year's budget development have not changed significantly from last year. Those expectations include the following:

O&M Budgeting:

- Budgets are well documented and supported by workpapers with clear assumptions linking the budget assumptions to historical data (actuals).

- Identify business drivers for cost increases, identify areas where cost reductions have occurred as the result of productivity improvements, adhere to established policies and procedures, and are accurately input into budgeting tools
- Data and supporting documentation are clear, with the ability to understand and explain changes when comparing on an object or Federal Energy Regulatory Commission (FERC) account basis
- Significant expenditures are budgeted in the same object account and FERC account where the actuals are expected to be charged
- Budgets incorporate lessons learned and measurable changes resulting from variance analyses

Capital and Deferred Budgeting:

In addition to the above expectations,

- Conservation Investment Programs (CIP) and Demand Side Management (DSM), as well as other rate recovery rider expenses and capital projects must be separately identified and budgeted
- Capital project cash flows are accurate beginning with the bridge year (actuals through April 2013 & forecast May-December 2013), carrying forward continuously through the budget period of 2014-2018, and in-service dates must be consistent with current project schedules, including the bridge year
- Careful attention is paid to routine parent work order details and accounting
- A focus on capital plant in-service is made such that, all current actual Construction Work in Progress (CWIP) balances are examined and work orders that represent plant being used are placed in service in the accounting records before the budget begins.

Your business area financial leaders should be your first point of contact, however, if you have general budget questions or require additional information, please feel free to call me at 612-215-4623 or you can contact Greg Robinson at 612-215-4631.

Table of Contents

2014 / 2018 O&M and CapEx Budget Development Timeline

For Calendar Year 2013 as of March 5, 2013

March 5, 2013	Budget Instructions issued
March 15, 2013	Issue Budget Documentation & Workpaper Requirements
Late March 2013	Issue O&M and Capital Spending Guidelines
March 19, 2013	PeopleSoft Load in CBS for 2014/2018 Budgeting Cycle
March 20 – May 9, 2013	Validation of Labor Utilization and other forecast data validation before budget create
May 9, 2013	**Final O&M (labor and non-labor) Due in CBS**
May 9, 2013	**Final Capital Budgets Due in CBS**
May 9, 2013	Run Labor Overheads with New Actuarial Information (EOD)
May 9, 2013	**Final Budget Capital Repository (Energy Delivery)**
May 10, 2013	**Final Budget Power Plant Feed (Corporate/Energy Supply)**
May 10-11, 2013	**Create 2014-2018 Budget version in CBS and ALS**
May 15 - 31, 2013	Complete GAAP and FERC Trend Analysis along with Regulatory Review
May 17, 2013	**Capital Financial Council Presentations due to Corporate**
May 29 - 30, 2013	**Financial Council Review/Approval of Capital Budgets**
June 3 – 7, 2013	**Incorporate Final Capital Changes with Executive Approval**
June 13, 2013	**O&M Financial Council Presentations due to Corporate**
June 26 - 27, 2013	**Financial Council Review/Approval of O&M Budget**
June 28 – July 5, 2013	**Incorporate Final O&M Changes with Executive Approval**
July 11, 2013	**Preliminary Budget Documentation: Narrative only**
July 12-July 31, 2013	Review of Preliminary Narrative
August 1, 2013	**Final Budget Documentation: Narrative only Due**
August 31, 2013	**Budget Workpapers Due**

Green=Key capital dates
Blue=Key O&M dates
Red=Key budget system dates

The business areas may also provide business area specific deadlines for completion and review that must be met. Please contact the designated financial liaison/representative for your business area for specific dates (see *Business Area Contacts*).

The Corporate Budget Calendar is also available on the *Corporate Budgeting Home Page.*

Navigation Guide and References

Background

The O&M and Capital Reporting and Analysis department (Budgeting) within the Chief Financial Officer's (CFO's) organization is responsible for the coordination of two components of the corporate budget - the five-year O&M budget and the five-year Capital budget using the CompetiSoft Budgeting System (CBS). The business areas, functional areas and legal entities across Xcel Energy input their O&M and Capital budget details into CBS.

The Budget Instructions summarize the corporate information that business areas need to prepare. The Budget Instructions are issued to members of the Financial Performance Team and all of the business area representatives. The business area's representative on the Financial Performance Team will be the principal contact throughout the budgeting cycle. They are also responsible for integrating the Budget Instructions and policies with business-area-specific instructions and communicating the integrated package to all members of their organization that will be participating in the budgeting process. The Budget Instructions are also available on the *Corporate Budgeting Home Page*.

The Budget Instructions are organized to be effective, efficient and as user friendly as possible for the business areas. The preceding first section of the Budget Instructions provides an overview of the purpose and importance of the corporate budget, major changes from last year's Budget Instructions, and expectations of business areas in preparing budgets. The preceding Corporate Budget Calendar is provided and contains important dates for key activities throughout the budget cycle.

Immediately following this section is information related to using the Budget Instructions and who to contact to answer budgeting questions. Following that, the main body of the Budget Instructions is organized into three sections: Budgeting Labor Costs, O&M Budgeting and Capital Budgeting. Each of these sections provides users with relevant budgeting information (General Guidance), corporate assumptions and directives (Assumptions) and "must do" specific instructions (Requirements) to use in preparing that portion of their budgets. Appendices have also been included to provide users with budget tool and accounting policy information, as well as a glossary of terms applicable to budgeting.

As users prepare their budgets, they should remember that budgeting is a key component of the framework for developing supportable and attainable financial plans by legal entity, utility and jurisdiction.

Navigation Guide

Several features have been included to facilitate the use of the electronic version of these Budget Instructions in the development of O&M and Capital budgets:

- The Table of Contents allows users to click on a topic and be automatically directed to that specific section.
- Throughout the document "links" have been inserted. Users are automatically directed to the document being referred to when clicking on these "links" or underlined text.
- The Corporate Budget Calendar highlights the important corporate deadlines for the input and review associated with the budget process. It is essential that users adhere to the dates provided in the Budget Instructions. Business areas may provide supplemental instructions and may also establish business area specific deadlines for input and review of budget data that must be met. Please contact the designated financial liaison/representative for your business area for specific dates (see *Budget Help*).
- Guidelines for preparing the required Budget Documentation (a resource based summary of budget activity by business area) and Workpapers (detailed information to support budget dollars and related documentation) will also be distributed in March 2013. See the *Budget Documentation & Workpaper Guidelines* published on the Corporate Budgeting Home Page for more information.

- A Glossary of budget terms and acronyms is included in the Appendices.

References

This document provides links to the Corporate Budgeting Home Page where you can find electronic versions of the Budget Instructions and the Budget Documentation & Workpaper Guidelines as well as links to other helpful tools and information, including:

CBS References
- *CBS Training Guide*
- *Rules for Project Date Moves*
- *Troubleshooting CBS – FAQs*

General Information
- *Budget Documentation & Workpaper Guidelines*
- *Business Systems-IT Product Information*
- Business Systems Contacts
- *Company Travel and Employee Expense Reimbursement Policy*
- *Dues and Other Guidelines*
- *Environmental Budget Guidelines*
- *FERC Uniform Systems of Accounts Manual*
- *JD Edwards Regulatory Ledger Training*
- *JD Edwards Training*
- *Personal Communication Device Policy*
- *Service Company Training*
- *The Print Shop Price Sheet*

O&M References
- *Corporate Escalation Rates*
- *General Guidelines for Classifying Labor and Expenses to A&G or FERC Functional Accounts Policy*
- *O&M Object Account Description*
- *Employee Expenses Accounting Guide*

Capital References
- *Capital Asset Accounting Policy - Capital Budget Principles*
- *Capital Expenditure Budget Requirements Matrix*
- *Reason Code Definitions*

Budget Assistance

For questions on the budgeting process or treatment of area-specific O&M and Capital costs, contact the representatives below or call the Budget Hotline at 612-330-6077.

Energy Supply	Melissa Ostrom (NSPM O&M)	612-330-6424
Bill Wilcox	David Mills (SPS O&M & ES Service Organization O&M)	806-378-2727
Financial leader	David E Olson (PSCo O&M)	303-628-2967
	Katie Remmen (ES Capital, Engineering & Construction)	612-330-5860
	Lynn Olson (Technical Services)	303-571-7144
Operations Services	Joaquin Sanchez (Environmental, Fuels)	303-571-7783
Vicki Beer	Tabitha Moore (Supply Chain)	612-330-5719
Financial leader	Linda Richards (Fleet)	303-571-7443
Nuclear Generation	Jeremy Johnson (Manager, Budgeting and Reporting)	612-215-4647
Linda Erickson	Diane VanDeWalker (Prairie Island)	651-388-1121 x4183
Financial leader	Jim Johnson (Prairie Island)	6513881121 ext 7301
	Marcia Heigl (Manager, Budgeting and Reporting, Monticello)	763-271-5899
	Lisa Grigas (Monticello)	763-271-5140
	Ranae Cipala (Monticello)	763-271-5109
Nuclear Amortization	Charles Jacobs (Manager)	612-330-2834
Karen Everson		
Financial leader		
Distribution Operations/Gas Systems	Liz Gauna-Giacomini (O&M Manager)	612-330-1982
	Cherie McMillan (Capital Manager)	303-571-3644
John Phibbs	Nate Harrington (NSPM)	612-330-5869
Financial leader	Derek Banovetz (NSPW)	612-330-5725
	Dolores Landavazo (Gas Systems)	303-294-2129
	Kim Kistler (PSCo)	303-571-7910
	Bryan Craig (SPS)	303-294-2357
Transmission	Mary Ohland (Capital)	612-330-1920
Scott Watson	Laurie Wold (Support O&M)	612-330-5510
Financial leader	Cathy Rose (Support O&M)	612-330-6012
	Matt Kaemmerer (Support O&M and Capital)	303-571-7315
Benefits	Todd Degrugillier (Manager)	612-330-6557
Mark Moeller	Kris Lindemann	612-330-5508
Financial leader		
Shared Services Finance Orgs	Kim Locker (Director, Business Area Finance)	303-294-2364
Kim Locker	Nate Young (Manager, Budget and Reporting)	303-294-2258
Financial leader	Darian Brend (Business Systems)	612-330-6008

	Cindy Curry (Capital for Business Systems)	303-571-7881
	Keith Tanzyus (Property Services and Security)	303-294-2322
	Peggy Stevens (Financial Operations and CEO)	303-294-2817
	Kimberly Hardy (Capital and Business Systems)	303-294-2010
	Cindy McShane (Chief Administrative Officer, Human Resources and Safety)	303-571-7359
Group Utility President	Raynard Gray (Manager)	303-294-2488
Janet Schmidt-Petree	Mike Hager (NSPM & DSM)	303-571-7472
Financial leader	Amy Madsen (SPS and Commercial Operations)	303-294-2409
	Kristan Butterfield (NSPW, PSCo, marketing, revenue requirements, and Regulatory & Strategic Analysis)	303-294-2288

Capital Asset Accounting Business Area Liaisons

Budget Organization	CAA Liaison	Phone
Corporate Services	David Adams	303-294-2094
Transmission	Ray Hetherington	612-330-5565
Distribution	Becky Dean	303-294-2395
Energy Supply NSPM	Carol Callahan	612-330-7659
Energy Supply NSPW	Dave Amans	715-737-2495
Energy Supply PSCo	Kris Jenson	612-330-5583
Energy Supply SPS	Denise LeGault	303-294-2093
Nuclear Generation	Jake Miller	612-330-1959

Budgeting Labor Costs

On March 19, 2013, a PeopleSoft load into CBS will update the current forecast to reflect any personnel changes that have occurred since the January 2013 PeopleSoft load. These are the current merit increases assumed for 2014-2018:

2014-2018

Company	BENEFIT	EXEMPT	NON-BENEFIT	OTHER-BENEFIT	UNION*
NSPM	3.00%	3.00%	3.00%	3.00%	3.00%
NSPW	3.00%	3.00%	3.00%	3.00%	3.00%
PSCo	3.00%	3.00%	3.00%	3.00%	3.00%
SPS	3.00%	3.00%	3.00%	3.00%	3.00%
XES	3.00%	3.00%	3.00%	3.00%	N/A

* - Union increases should be budgeted based on the specific contract. These rates are the best estimates as of March 1, 2013 and are subject to change.

Labor expense budgets are created by identifying projected employee levels and appropriate wage rates for each budget year. The wage rate of each active employee will already be in the system at the beginning of the budget process through the PeopleSoft load. The budget system also includes estimated overall wage percentage increases by labor category (union vs. non-union, etc.) that are applied to each employee's wage rate to estimate the budget year labor dollars. Labor budgets should be direct charged when possible to the company benefitting from the services to be provided.

General Guidance

Labor Resources

Xcel Energy employees are divided by labor resource categories in order to better define their assignment to JD Edwards (JDE) business units. The resource categories are:

- Exempt – full-time salaried employees
- Benefit – hourly full-time non-union employees
- Other benefit – hourly part-time benefit employees
- Non-benefit – hourly part-time temporary employees without benefits
- Union – full-time hourly bargaining employees
- Contract – see the document titled *O&M Object Account Description* published on the Corporate Budgeting Home Page for specific JDE object account uses
- Premium time – shift differential pay
- Overtime – straight time, double time or time and one-half by each labor category

Labor Management

Throughout the year, PeopleSoft data will be refreshed in CBS after normal wage increases go into effect. These updates take place in January (NSPM, NSPW and Nuclear union), March (non-bargaining), July (PSCo union) and November (SPS union). Users will be notified when these refreshes occur and are required to validate headcount following the update. Users are also required to verify that employee labor includes annual wage increases; especially if new employees are added after the wage increases are loaded.

Assumptions

General Wage Increase

A general wage increase will be applied in the 2014-2018 budgets systematically as noted above. For bargaining employees, the wage increase will be based on the contract agreements with additional guidance from Compensation and Executive management for the years not covered by a contract.

Hours Per Month

Available labor dollars in CBS are calculated based on the available hours per month. The number of available hours per month varies from year to year, depending on the timing of weekdays/weekends for each calendar month. The schedule below shows the hours per month used in the calculation of the monthly spread of hours in CBS.

Exempt, Benefit, Union & Other Benefit

Year	2014	2015	2016	2017	2018
Jan	184	176	168	176	184
Feb	160	160	168	160	160
Mar	168	176	184	184	176
Apr	176	176	168	160	168
May	176	168	176	184	184
Jun	168	176	176	176	168
Jul	184	184	168	168	176
Aug	168	168	184	184	184
Sep	176	176	176	168	160
Oct	184	176	168	176	184
Nov	160	168	176	176	176
Dec	184	184	176	168	168
Total Hrs	**2,088**	**2,088**	**2,088**	**2,080**	**2,088**

Non-Benefit (no paid holidays)

Year	2014	2015	2016	2017	2018
Jan	176	168	160	168	176
Feb	160	160	168	160	160
Mar	168	176	184	184	176
Apr	176	176	168	160	168
May	168	160	168	176	176
Jun	168	176	176	176	168
Jul	176	176	160	160	168
Aug	168	168	184	184	184
Sep	168	168	168	160	152
Oct	184	176	168	176	184
Nov	152	160	168	168	168
Dec	176	176	168	160	160
Total Hrs	**2,040**	**2,040**	**2,040**	**2,032**	**2,040**

Incentives

The executive officer and corporate incentive plan programs are budgeted corporately at the legal entity level. Business areas should not include any amounts in their budgets for these compensation programs. Business area specific incentives and bonuses are discussed in the O&M Budgeting section of these instructions (see *Employee Incentives and Other Compensation*).

Employee benefit Labor Loadings *(Pension Plan and 401K, Healthcare, Worker's Compensation, Incentive & Payroll Taxes)*

Employee benefit labor loadings are calculated within CBS and are budgeted corporately at the legal entity level. Business areas should not include any amounts in their budgets for these loadings. The labor loading rates will be applied by CBS to budgeted productive labor with the resulting labor loads following budgeted labor to produce a total labor budget by JDE business unit.

Non-Productive Labor Loading

Non-Productive labor loadings are also performed within CBS. Non-Productive Time (NPT) is time that an employee is not working because of Paid Time Off (PTO), floating holidays, jury duty, etc. In order to accurately develop rates for non-productive labor, it is critical to have an accurate monthly pattern of base wages. This requires an accurate count of employees and accurate rates for each employee. On an annual basis, CBS allocates approximately 83% of wages to productive labor and approximately 17% to non-productive labor. The non-productive labor loading rate is applied to O&M productive labor to determine the amount of O&M non-productive labor to record in object account 711143-Non-Productive Labor.

Attrition / Vacancy Labor Loading

A negative attrition / vacancy rate will be loaded based upon productive labor in order to account for expected corporate vacancy rates. The following JDE object accounts are used to record attrition / vacancy:

- 618099 - Fuel Handling Labor-Attrition
- 618419 - Fuel Procurement Labor-Attrition
- 618429 - Nuclear Fuel Procurement Labor-Attrition
- 711146 - Productive Labor-Attrition
- 730380 - CWIP Productive Labor-Attrition
- 747125 - Clr Productive Labor-Attrition
- 748118 - Def Productive Labor-Attrition
- 740398 - RWIP Productive Labor-Attrition

Business areas should remove all negative pseudos (vacant positions) currently in CBS for attrition / vacancy. Managers should not be budgeting for attrition / vacancy. Business areas are responsible for managing to the total of productive labor less attrition / vacancy.

Requirements

Naming Convention for Pseudos

Due to ongoing pseudo reporting, a naming convention has been designed in order to report on the types of pseudos in each business area. In the 255 character description field, pseudos must begin with one of the following two character designations followed by a dash (**-**):

- **Replacement (PR)** – Employees who have been terminated or transferred and a replacement is anticipated. Generally a pseudo for a position that is currently vacant, possibly for a position that will be vacant in the near future, assumes the current employee is zeroed out now or in the near future.
- **New Hire (PN)** – New positions that have been formally approved as part of the workforce plan. Generally a pseudo for a position that adds to total staffing level due to a new or expanded function.
- **Advanced Hire (PA) –** Positions that will be vacated in the future where multiple years of training are required by the position or a union contract.
- **Intern (PI) -** A pseudo to identify open intern positions.

Labor Utilization Validation

After the March 19th PeopleSoft load has been completed, users should verify in CBS that the employees and base wages for each JDE business unit are correct. Please add, delete or create pseudos (vacant positions), and update wage rates, where necessary, to reflect promotions, etc. If a new pseudo is created, users must fill in the appropriate hours in the NPT box for each year. See the *CBS Training Guide* published on the Corporate Budgeting Home Page for more information. Each business area is responsible for reviewing all of their labor departments to verify the following:

1. Labor is fully utilized (i.e., distributed to O&M or Capital)
2. Employees are shown under the correct labor department

3. Pseudos are eliminated in all cases where the vacant position has been filled
4. Pseudos have been added for those positions that are approved as part of the workforce plan, but not yet filled
5. Employees that need to be transferred to another labor department have had a personnel action form (PAF) completed prior to making the transfer in CBS

Users should run a labor utilization report in CBS to assist in validating that labor is fully utilized. As noted on the Corporate Budgeting Calendar, the period from March 20th through May 9th will be used to complete a final corporate check on labor utilization, and to ensure labor aligns with the workforce plan. Please contact Irina Demuth at 612-330-1978 for any questions regarding labor utilization.

O&M Labor

O&M labor entered into CBS must be entered using object account of 711142–Productive Labor.

Capital Labor

Labor that is direct charged to a capital work order or capital Engineering and Supervision (E&S) work order should be entered into CBS in object account 730390-CWIP Productive Labor, or 740399-RWIP Productive Labor, with a subledger "99999999" and a subledger type "W." ***Please, DO NOT USE subledgers 99999997 or 99999998 any more to budget for standard capital labor. However, there is one exception to this rule. If the labor is for capital work that will be part of an IT project, then use the 99999998 subledger. Make sure to work with your Business Systems contact on this. Please note that this is a change from last year.***

O&M Budgeting

The purpose of the Corporate O&M budget is to plan O&M expenses for the next five years. The business areas are responsible for developing the five-year detailed O&M budget by legal entity and business area, and entering the information into the current forecast version of CBS. Detailed O&M budgeting is required for 2014-2018.

Each business area is responsible for reviewing its O&M budget to ensure that it is consistent with on-going business planning requirements. After the business area executive has approved the budget, it is presented to the Financial Council for their approval. If the Financial Council requests any revisions, the changes are made in CBS by the business areas.

There are two types of expenses included as part of the O&M budgets: labor expenses and non-labor expenses. The labor expense portion of the O&M budget was discussed in the previous section. Non-labor expenses are budgeted in several categories or cost components. These categories are identified for each business area and are designed to assist in providing an overall summary of major cost component areas that are discussed later in this section.

General Guidance

CBS Instructions

The O&M input tool for the 2014-2018 budget is CBS. CBS is configured to build budgets consistently with actual accounting data. JDE is set up to interface with CBS. JDE loads actual accounting data into CBS and the Allocation Ledger System (ALS) for comparison and variance analysis. Business areas are accountable for the reporting of budgeted information and variance analysis from all reporting views including, but not limited to, legal entity, business area and regulatory reporting. The Business Objects reporting tool provides several universes that can be used for this variance analysis.

All budgeting occurs in the current forecast version. Periodic copies may be made to coincide with the various deadlines. Additional information regarding the specific dates of the copies will be communicated as the budget process progresses.

The following documents have been prepared to assist users. See the links below, or reference the document that is also published on the Corporate Budgeting Home Page.

CBS Training Guide

CBS Tool Link

Troubleshooting CBS – FAQ's

JDE Subledger and Subsidiary Field Guidance

Each labor and non-labor budget record is assigned to an account string (JDE business unit, JDE object account and JDE subledger (when necessary)). The account string is used to assign the expense to the appropriate legal entity, as well as the appropriate FERC account and utility (e.g., gas, electric). This assignment to the account string is also used as the basis to develop electric or gas cost of service studies. It is important to budget to the same object and FERC where you expect your actuals to be charged. Instructions on JDE subledger fields and subsidiary fields used in the development of O&M budgets is contained in the Appendices, and can be accessed by the following link: *JDE Guidance*.

Budgeting Principles

Labor costs of employees reporting to, and non-labor costs controlled by, the management of each group must be 100% budgeted and paid for by that manager. For example, the manager who chooses the consulting company and oversees its work pays the charges for consultants and contractors. Cross-charges between departments do not move the budget dollars or variance responsibility to another area. It is recognized that some invoices, such as corporate dues, may be split among management when agreed to by all parties.

Assumptions

Environmental

Environmental expenses associated with air, water and waste remediation should be budgeted in accordance with the *Environmental Budget Guidelines* published on the Corporate Budgeting Home Page.

Subscriptions On-Line

Object account 725005-Subscriptions On-Line, should include expenses for subscriptions and reference materials which are received using an online tool, or reports or data which are received electronically using an online tool. Examples include any Information Service Provider (ISP) or third-party hosted systems provider.

Facilities

The Property Services organization is responsible for budgeting all O&M costs for facilities managed by Property Services (e.g., headquarters, call centers, service centers) including: facility rental or lease costs, and all costs associated with the ongoing activities necessary to operate and maintain the leased and owned facilities, unless covered by the rental or lease agreement. This includes such items as climate control, lighting, snow removal, lawn service, landscaping, grounds maintenance, mowing and sprinkler systems when not covered by the applicable rental or lease agreement.

Facilities space and O&M costs are budgeted by Property Services, except for the following:

- Fleet, Sourcing, and Logistics as these areas budget their facilities costs within their own clearing accounts,
- Energy Supply which budgets for their own plant facilities operations and maintenance costs, and
- Electric and gas use costs at operational facilities, such as gas regulators sites, microwave and radio towers, power plants, substations, etc.

Requests for facility services (O&M and capital) should be submitted to Property Services. For more information, please contact Keith Tanzyus at 303-294-2322.

Copiers – Business Systems Managed Copiers Only

Business Systems will manage and budget for the corporate copier program. Business areas will remain responsible for paper, color toner, and special request copier costs, including copier lease, maintenance, usage (meter) charges, toner, and staples. Contact Dave Dalum at 612-330-5899 or Jon Rouse at 612-330-1905 if you have questions about whether or not your copier is managed by Business Systems or is considered a special request copier.

Printing Services

Business areas will remain responsible for budgeting their printing costs. The Print Shop Price Sheet provides estimated costs for various print shop services.

Budget printing costs to JDE object account 714100-Print/Copy-Other for O&M expense, 748170-Def Materials for deferred expense, account 731800-CWIP Materials for Capital expense, or 747510-Clrg-Print/Copy for clearing expense.

Postage/Carrier (e.g., FedEx)/Inter-Company Mailings

Business areas are responsible for budgeting all USPS postage. All FedEx, UPS and other carrier mailings will continue to be charged in full to the sender's business area and are not budgeted by Property Services. Intercompany mailings will continue to be budgeted by Property Services; therefore the Business areas are not responsible for budgeting these costs.

Budget postage costs to JDE object account 723400-Postage for O&M expense, 748210-Def Postage for deferred expense, and 747920-Clr Postage for clearing expense.

Facility Waste

Property Services will continue to manage and budget for waste containers at Property Services managed facilities. These containers are intended for common facility waste only (i.e., the contents of employee, office, and lunchroom waste containers). Business areas will be responsible for managing and budgeting for the disposal of project and equipment waste (i.e., poles, cross arms, hardware, and equipment containers).

Information Technology (IT)

All IT capital project budgets are budgeted by Business Systems and should not be part of the business areas' budgets. This includes software implementations, as well as hardware capital purchases for PCs, LANs and printers that meet the capital guidelines. Business areas should not budget for software/hardware projects. However, there are certain exceptions to this rule. For example, plant control systems and related hardware are included in the Energy supply budget. If you have any questions, contact Diane Prentis at 612-330-5744. Also, as referenced in the preceding Capital Labor section, all capital labor associated with an IT project should be budgeted by the business area using subledger 99999998. Make sure to work with your Business Systems contact on this. Please note that this is a change from the last budget cycle.

If you have a new IT initiative, such as a new application system, new support or a non-standard purchase, please contact the Business Systems area directly to discuss your initiative. The contact list can be found under the following link Business Systems Contacts. This information is important so that Business Systems can budget and plan accordingly.

Efficient use of personal computing assets enables Xcel Energy to leverage volume purchases, minimize support costs through product standardization, promote compatibility between IT assets and Xcel Energy's computing environment, monitor compliance with software licensing/data security, and maximize return on investment by carefully managing the lifecycle and use of these assets. For additional information about IT management standards please refer to the following link: *Business Systems Standard*

IT Investment Closed Loop Process

Business areas that have projects that have been approved by the IT Investment Council where hard savings will be realized are required to budget the savings that were presented for all applicable periods. If you have any questions, please contact Greg Robinson at 612-215-4631.

Insurance Premiums

Liability and property insurance (insurance expense related to insurable accidental events) will be budgeted corporately by the Hazard Insurance department. Business areas should not include any amounts in their budgets. If you have any questions, contact Mike Anderson at 612-215-5366 or John Hernick at 612-215-5349.

Supply Chain Sourcing - Category Management

Supply Chain Sourcing (Supply Chain) has identified certain key categories of spend for which it gathers market information and leverages spend of the company to pursue strategic contracting strategies, including price reductions, volume discounts, lead time preferences, etc. All budgets impacted by the categories below should contact the assigned category manager for the most current information regarding price assumptions for the spend category.

Category	Category Manager
Boiler Systems, Boiler Maintenance Services, Turbine/Generator Services	William Smith
Cable & Wire, Circuit Breakers, Transformers (Power)	David Reitz
MRO / VMI	Rick Pelletier
Chemicals, Gases & Lubes	Brian Hastings
Engineering Services	Brian Owen
Metal Structures, Wood Poles, Vegetation Mgmt	Bob Kunze
Travel Services, Staff Aug. / Personnel Services	Bob Wagner
IT and Telecom	Bob Wagner

Purchasing Rates

Each business area is responsible for budgeting purchasing loads. A loading rate of approximately 1.0% (actual allocation rates may differ slightly depending upon jurisdictional procurement activity and compliance with Corporate Policies) is to be applied to all purchases of material and services, including inventory, subject to a transactional limit. Purchasing loads should not exceed $3,500 per invoice per purchase order (PO) or PO release per invoice. For example, an invoice of $550,000 for material purchases for one PO would receive a purchasing load of $3,500. Purchasing loads do not apply to nuclear purchases. For more information, contact Linda Richards 303-571-7443 or Tabitha Moore 612-330-5719.

Business areas are also responsible for budgeting Supply Chain labor and expenses in instances where sourcing/purchasing employees are performing work for a specific capital project. Capital project codes must be supplied to the Supply Chain sourcing and purchasing personnel prior to commencing work on a project in order to accurately charge labor and any associated expenses.

Warehousing Rates

Each business area is responsible for budgeting warehousing loads within their materials object account. Due to different charging methodologies and systems, different rates apply for the Distribution and Transmission business areas, as well as for the Energy Supply organization as described below:

<u>Energy Supply</u>: The following rates will be applied to material purchases with the load being limited to $3,500 per Purchase order, excluding any required true-ups for over or under collections. True ups will occur at each quarter end. Hayden and Sherco are excluded from the stores loading process as those costs are direct charged. The loads are used to offset costs incurred by storeroom personnel for receiving, handling, storing, & issuing materials as well as any costs incurred by the Logistics central support group. If you have any questions contact Ken Heupel at 720-497-2040.

NSPM	4.50%
NSPW	0.65%
PSCo	4.50%
SPS	4.75%

Distribution and Transmission: Apply the following warehousing rates to purchases of materials.

Stock material (handling, storing, issuing and delivery)

NSPM	15%
NSPW	14%
PSCo	17%
SPS	7%

The rates provided above are as of November 30th, 2012

Re-stock material: NSPM, NSPW, SPS – 17%; PSCo – 0%

Please contact Linda Richards at 303-571-7443 or Tabitha Popma at 612-330-5719 with questions.

Joint Ownership Share

Special accounting treatment may apply when budgeting costs to jointly owned facilities. For guidance, please contact:

Carrie Dyer	303-294-2385	General joint ownership accounting
Chris Keiss	970-276-2226	Hayden Station (PSCo)
Stan Rogers	719-549-3752	Comanche Station (PSCo)
Annie Lord	719-549-0321	Comanche Unit 3 (PSCo)
Todd Griesert	763-261-3106	Sherco Station (NSPM)

Direct Support of Outages at Prairie Island or Monticello Nuclear Plants

The direct support of nuclear outage related expenses (i.e., labor and employee expenses) may be eligible to be amortized over the nuclear plant operating cycle. If you plan to support nuclear outages during this budget cycle, please contact Marcia Heigl for Monticello at 763-271-5899 and/or Mark Aeling for Prairie Island at 651-388-1121 x5228 for a determination whether the work meets the outage accounting policy and for a subledger to use in the development of the budget.

Requirements

Budget Documentation and Workpapers

Budget Documentation is required for all business areas by operating company. This is a broad, resource based summary of budget activity for each business area. The format and level of detail required is consistent for all of the business areas and operating companies. See the *Budget Documentation & Workpaper Guidelines* published on the Corporate Budgeting Home Page for specific requirements and templates. A checklist is provided in the Budget Documentation & Workpaper Guidelines. Please use this in preparing your documentation. It is important to remember that maintaining well-documented budget assumptions and explanations to support your budget is a critical element of managing the business and may be used to support forecasted test year rate case filings.

Budget Workpapers are also an integral part of the budget process for all business areas. Budget Workpapers should provide detailed information to support budget dollars and budget documentation.

IT O&M Requests

All requests for IT products and services (adds/moves/changes, hardware, software, IT support, systems access, security updates, etc.) must be submitted through *Mercury*, the company's IT request system.

Business areas that expect to need new IT products and services for the 2014-2018 budget years should communicate this to the Business Systems Business Technology Executives (BTEs) (see Business Systems Contacts.) The BTEs need to incorporate these expenses in the Business Systems budget, and the BTE's need to prioritize and approve these IT initiatives.

Monthly Budgets

For the budget to be useful in managing the company's business and monitoring financial performance, it is critical that the monthly budget accurately reflects when users expect to incur expenses during the year. Best estimates of when planned costs will be charged to a JDE business unit should be used in the development of the monthly budget, as this provides support for estimating cash flow requirements. The monthly budget is as important as the annual budget. The monthly budget deviations (and forecast updates), which are reported throughout the year, are a primary indicator used to monitor financial performance throughout the year. The monthly budget estimates may also be used in the event of a rate case filing in which the test period crosses two calendar years. Do not budget the same amount for each month unless the budgeted expense is anticipated to be incurred in this manner. Any escalation of costs should be based on known factors such as historical costs or anticipated increases. Your basis for increase should be well documented as part of your budget workpapers. For general inflation increase estimates refer to the *Corporate Escalation Rates* published on the Corporate Budgeting Home Page.

Third-Party Billings

Business areas must include in their O&M budget all expenses that are billed to third parties (i.e., parties outside of the Xcel Energy holding company system). Examples of third-party billings include: relocating distribution and transmission facilities for the accommodations of others, repairing damages to company property and working on customer owned electric distribution facilities. The proceeds from third-party billings must be accounted for in the revenue accounts, so do NOT net the proceeds with the O&M expenses, and do NOT enter the revenue into CBS. Revenues for billing work orders in JDE will automatically be calculated in ALS and then sent to CFM. Business areas do NOT need to send their revenue information to Financial Forecasting for input into CFM since the revenues will automatically be calculated. However, revenues related to billings NOT set up as billing work orders in JDE, need to be submitted to Financial Forecasting for inclusion in CFM.

For example, if NSPM incurs $2,000 in O&M expense for right-of-way maintenance of a transmission line that is billed to another utility company (not part of the Xcel Energy holding company system), the $2,000 expense is budgeted in O&M expense, and the proceeds from the billing are budgeted in CFM under Other Electric Revenue. Please contact Erin McGuire at 612-337-2331 if you have billings outside of the JDE billing work order process.

Capital billings should not be included in the O&M budget, but rather as capital expenditures using the appropriate object account for such billing.

Xcel Energy Services (the Service Company or XES) must bill all O&M costs to another Xcel Energy company. Once the O&M costs are billed to the appropriate Xcel Energy company, they can then be billed to the third party. Generally, the Service Company expenses are billed to one of the operating companies, unless the third party billing is for additional expenses incurred for an Xcel Energy company that has been sold. In that case, Service Company bills the intermediate or parent holding company of the sold company, and then the intermediate or parent holding company bills the third party. Revenue is recorded on the company (operating or holding company) that billed the third party and not on the Service Company.

Employee Incentives and Other Compensation

Incentives

Any business area specific incentive cost that is in addition to, or different from, executive officer or corporate incentive plan programs must be budgeted within each business area in object account 711230-Incentive. Costs budgeted to this object account must be for incentive plans that have been pre-approved by Human Resources.

Bonuses
Any business area specific bonuses above and beyond the corporate incentive plan program must be budgeted within each business area to object account 711270-Other Compensation. The Spot-On Bonus Program is budgeted at the corporate level and should not be included in business area budgets.

Employee Performance Recognition
This includes employee performance recognition such as Thank You's, Above & Beyond awards, Premiere Choice awards, company store items and recognition meals presented to acknowledge employees for a specific business related action or result. This should not be budgeted by individual business areas as it is budgeted corporately in object 721850.

Safety Recognition
Safety Recognition is the responsibility of individual business areas. Object account 721800 should be used to budget for any safety related recognition.

Life Events
Life events include promotions, retirements or special occasions. These should be budgeted by individual business areas in object 721810.

Non-Recoverable Recognition
This object account 721851 is for year-end celebrations, which is only to be used if there is corporate approval and notification from management that funds are available. This will be evaluated each year and is at the discretion of the Company. This should not be budgeted by individual business areas, or used for actuals without corporate approval.

Consulting Services and Contract Labor

Legal Consulting Expenses
The General Counsel business area is responsible for managing all legal matters, including engaging and approving the use of outside legal vendors. Internal business clients and in-house counsel may reach an agreement that business areas will bear the cost of certain legal matters. General Counsel will relay this information to the appropriate finance person in the particular business area. During the budget process, business areas must contact General Counsel to convey information related to projects that are anticipated during the 2014-2018 budget years that require assistance from General Counsel.

Contact Deb Meuwissen at 612-215-4545 or Kimberly Hardy at 303-294-2010 if you have any extraordinary projects that will require significant legal services, so the General Counsel budget can be planned.

Other Consulting Expenses
For additional guidance on budgeting consulting and professional services in JDE object accounts please see the document *O&M Object Account* Description published on the Corporate Budgeting Home Page.

Contract Labor
Object account 712110-Contract Labor should only be used for expenses for persons who are engaged in short-term (less than a year), temporary or special purpose work that is supervised by a company employee. It includes temporary labor payable to a third party that replaces company labor for routine daily activities. It does not include expenses for employees of the company.

Contract LT Outside Services
Object account 713050-Contract LT Outside Services, should include expenses for persons who are engaged in long-term (more than a year) special purpose work. It includes, but is not limited to, the following services: tree trimming, meter reading, construction crews, scanning and imaging invoices or professional outside services that have material costs. It does not include: facilities operations and maintenance, printing, copying, office machine maintenance, cell phones, office supplies or expenses for employees of the company.

IT-Personal Communication Devices and IT Supplies

Each business area is responsible for budgeting personal communication devices and consumable supplies for their business area. Budget communication device costs in object account 715600-Personal Communication Devices.

For information on personal communication devices, refer to *Personal Communication Device Policy*

Budget fax machine leases in your business area in object account 723130-Equipment Rental. Fax machine leases should be budgeted by the business area primarily using the machine, unless otherwise covered by Property Services.

Budget other IT supplies (printer cartridges, pager batteries, projectors, etc.) in your business area using object account 714000-Materials.

Budget other printing service costs (e.g., Kinko's) in your business area using object account 714100-Print/Copy–Other.

Note that the following JDE object accounts can only be used by IT:

- 715100 - IT Hardware Maintenance
- 715200 - IT Hardware Purchases
- 715300 - Software Purchases
- 715400 - Software Licenses
- 715500 - Software Maintenance
- 715700 - Network Services
- 715710 - Network Voice
- 715720 - Network Data
- 715730 - Network Telecom
- 715740 - Network Radio/Pgr/MW
- 715800 - Mainframe Services
- 715810 - Distributed Systems Services
- 715820 - App Dev & Maint
- 715830 - Project Office
- 715900 – Application Service Provider

Employee Expenses

Employee Expenses include non-office supplies, reimbursable expenses incurred on the job, individual training, and similar items. When traveling, this includes meals, food items (including catering for onsite/offsite meeting refreshments), offsite meeting/events, lodging, parking, telephone calls, tolls and other transportation expenses.

The following sample object accounts are available to accurately account for employee expenses: Also refer to *the Concur Expense Report Object Account Codes* for a complete list including definitions of expense types and their corresponding JDE object accounts.

- 721005 - Airfare
- 721010 - Car Rental
- 721015 - Taxi/Bus
- 721020 - Mileage
- 721025 - Conferences/Seminars/Training
- 721030 - Hotel
- 721035 - Meals – Employees
- 721040 - Meals – Including Non-Employees
- 721045 - Parking
- 721050 - Per Diem

- 721055 - Safety Equipment
- 723850 – Recognition - Entertainment
- 721060 - Other

All employees are expected to use sound judgment and plan business travel to minimize costs. In addition, Xcel Energy has negotiated discount or contract rates with its preferred vendors. As budgets are developed for employee expenses, take this information into consideration. The *Company Travel and Employee Expense Reimbursement Policy* also includes additional information. In addition to these items, there are specific requirements for the employee expenses addressed below.

Entertainment expenses are not considered employee expenses and should not be budgeted in the above accounts. Entertainment, including travel, meals and alcohol, should be budgeted in object account 723855-Other Deductions. Tickets for entertainment events should be budgeted in object account 723854-Deductions Corp Tickets. The *Company Travel and Employee Expense Reimbursement Policy* includes additional information on Entertainment expenses. The following are examples of entertainment accounts:

- 723854 – Entertainment - Tickets
- 723855 – Entertainment – Meals

Air Travel
Use object account 721005-EE Airfare for all air travel costs. Budget air travel expenses in the JDE business unit that will be used when booking your flight.

Corporate Travel – There are no direct passenger charge backs for travel on the Xcel Energy corporate aircraft. Corporate aircraft expenses will reside in the Aviation Services' budget. Business areas are not responsible for budgeting for these expenses. Travel on corporate aircraft is limited. See the *Company Travel and Employee Expense Reimbursement Policy* for priority in using company aircraft. If you have any questions, contact Jennie Ator at 303-571-6728.

Commercial Travel – The Carlson Wagonlit travel fees are slightly reduced, but please note that certain of the fees were not booked to the individuals BMO cards. For the 2013 budget, see table below for the fees that will be processed against the BMO card (last column). It is highly recommended to use the GetThere travel tool to book air/hotel/car to take advantage of corporate discounting and other benefits. Each area is responsible for budgeting the service fee in addition to their air travel costs.

Description:		**New Fee Structure Point of Sale (what charges you will see on your BMO card for 2013-2018)**	**Post adjustment which includes COLA multiplier for 2013. Estimated at 2.5%**
Unassisted online		$11.00	$11.03
Car/hotel only unassisted online		$9.00	$9.02
Assisted online - Domestic			
Minneapolis assisted		$28.40	$28.47
Automation assisted		$28.40	$28.47
Assisted online - International			
Minneapolis assisted		$28.40	$28.47
Automation assisted		$28.40	$28.47

Agent Initiated - Domestic		$30.15	$30.23
Agent Initiated- International		$30.15	$30.23
Car /hotel only - agent initiated		$5.15	$5.16
Car/hotel only assisted online		$9.15	$9.17

For additional information, please see *Company Travel and Employee Expense Reimbursement Policy*.

Corporate Tickets
Tickets purchased for Nuggets/Timberwolves basketball games, Wild/Avalanche hockey games, Twins/Rockies baseball games, Broncos/Vikings football games, Opera, Orchestra Association and other social events should be budgeted to JDE object account 723854-Deductions Corp Tickets. Budget food and drinks purchased at these events to JDE object account 723855-Other Deductions.

Employee Move-Related Costs
Business areas are responsible for budgeting the costs associated with adds/moves/changes that relate to physically moving boxes or building/changing cube walls. The average cost of moving an employee is $500. Budget these costs to object account 723040-Adds/Moves/Changes. Property Services will charge the costs to your JDE business unit as they occur. If you have any questions, contact the appropriate representative for your state (see *Project/Tenant Services Contacts*).

Spouse Expenses
Executive approval must be obtained before spouse expenses can be included as a company expense. Spouse expenses may include airfare, lodging and meals incurred on an approved business trip, or for attending company functions/festivities. Budget officer's spouse or delegated employee's spouse expenses to JDE object account 723855-Other Deductions. In addition, these costs must be billed to the Xcel Energy Holding Company. To ensure these costs are billed to the Holding Company use the JDE subledger “999101” with a subledger type “W.”

Office Supplies Expense

Use object account 721500-Office Supplies to budget for office supplies. Office supplies include pens, pencils, paperclips, paper (copier, tablets, etc.), staplers, staples, toner cartridges, calculators, holders and containers for any of the above items, calendars, hole punches, desk cleaning supplies (Clorox wipes, canned air for blowing off dust and dirt, etc.), folders/binders (3-ring, report, etc.), tape (scotch, duct, masking, etc.), tape dispensers, computer accessories (mouse pads, wrist pads, monitor risers, etc.), envelopes, Post-Its, glue, phone headsets, and similar items. *Note: Keyboards and mice must be coded to IT Hardware Purchases.*

Do not code office supplies to Employee Expenses or Materials.

Transportation

Fleet Vehicle and Equipment Rates
To facilitate budgeting, all fleet vehicles and equipment for 2014-2018 will be charged by the hour. This approach works best to accommodate the use of the Passport Work Management System, and will enable fleet costs to flow to projects on a daily basis.

In order to comply with Corporate accounting guidelines, rates are reviewed each month and adjusted periodically as needed.

Each business area is responsible for budgeting both the O&M and Capital components for owned and rented vehicles and equipment charged through Fleet Focus. A list of units assigned under each manager area will be provided to the business areas for validation as part of this budget cycle.

Fleet costs are required to be budgeted at a detailed level in the appropriate JDE object, see list below. Any capital object account (73XXXX or 74XXXX) should use the 99999997 subledger with a type of W. Your transportation costs should be budgeted 100%, similar to the labor 100% utilization of labor.

- 618305 – Fuel Handling Fleet
- 681023 – COGS Transportation Fleet (HomeSmart only)
- 722000 – O&M Transportation Fleet Cost
- 732700 – CWIP Transportation Fleet Cost
- 742700 – RWIP Transportation Fleet Cost
- 747810 – Clearing Transportation Fleet Cost
- 748195 – Deferred Transportation Fleet Cost

The rates are designed to cover all of the costs associated with the vehicle or equipment. If you have any additional questions, please contact any of the following people: Overall – Mark Hennesy at 303-571-3809, Kay Ozanne at 303-571-7945, Ron Grady at 806-378-5416, or Wes Worthley at 612-630-4508.

Pool Cars
Pool vehicles are available in the following locations:

- Colorado: Lipan Distribution Center (LDC), Materials Distribution Center (MDC), 1800 Larimer, Boulder Service Center, Grand Junction Service Center
- Texas: Amarillo Tower, Amarillo I-40 Garage, Amarillo Southwest, Lubbock
- New Mexico: Roswell
- Minnesota: Chestnut Service Center, 414 Nicollet, Maple Grove Service Center, Rice Street Service Center, St. Cloud Service Center, Newport Service Center, White Bear Lake Service Center, Faribault Service Center, Mankato Service Center
- North Dakota: Fargo
- Wisconsin: Sky Park, Rice Lake Service Center, Menomonie Service Center, Ashland Service Center, Abbotsford Service Center, Amery Service Center, Hudson Service Center, La Crosse Service Center, Eau Claire Western Ave. Service Center
- Michigan: Ironwood Service Center

Pool vehicles are supported by the Fleet organization. Each business area is responsible for budgeting for pool car usage. These costs will be charged back to each user's JDE business unit.

Casual Use Rate
Employees using their personal vehicles for company business are reimbursed via SumTotal at the IRS Standard Mileage rate (2013 = $0.565 per mile). This expense must be budgeted under Employee Expenses as in the past. Casual Mileage is analyzed quarterly, and employees consistently averaging over 1,000 miles per month in Casual Mileage should be transitioned to an assigned company vehicle. Please contact Mark Hennesy at 303-571-3809 if this is the case.

Capital Non-labor Transportation Costs
To further support the Operations Finance analysis for supply chain, we are asking this year that the business areas not only budget 100% of labor with splits to O&M and Capital, but also ***budget 100% of transportation costs with splits to O&M and capital, as well. When identifying the capital component, please use the 99999997 subledger, with a type W***. Please note that we should not budget costs to transportation for labor or travel-related transportation expenses (such as car rental, taxi, or bus). The transportation objects (72xxxx, 73xxxx, or 74xxxx) should be used for Fleet supported costs only (bucket trucks, pool cars, etc).

Dues, Contributions and Sponsorships
A company policy has been implemented regarding dues, contributions and sponsorships to ensure that the company remains in compliance with reporting and regulatory requirements.

See the document called *Dues and Other Guidelines* on the Corporate Budgeting Home Page for the policy related to each type of expense.

Please contact Julie Rushton at 612-330-2809 for questions related to due, contributions and sponsorships and contact Mary Pope 612-330-6574 regarding regulatory treatment.

O&M Projects with Special Rate Treatment

All eligible O&M projects and/or eligible expenditures associated with rate riders or other special rate treatment must be updated with the most accurate estimates for the budget, as well as monthly forecast updates. Each project should be budgeted separately to facilitate identification. Examples of such projects/expenditures include the various distribution initiatives associated with the Central Corridor project.

Legal Settlement Expenses

Xcel Energy business areas are responsible for bearing the costs of legal settlements not covered by insurance. Allowance for settlements should be budgeted under object account 723480-Injuries & Damages by the business areas at a high level, not specific to any particular matter, based on the business area's three-year historical average settlements paid. Verify that you've budgeted to the correct utility (electric, gas, common) as well. During the budget process, business areas should contact the General Counsel business area to coordinate information and budgets for settlements anticipated during the 2014-2018 budget years. Contact Deb Meuwissen at 612-215-4545 or Kimberly Hardy at 303-294-2010.

Capital Budgeting

The budgeting of capital expenditures and additions to plant in service includes identifying and prioritizing resources to support operations and future plant investments. The capital forecast, maintained and periodically updated in CBS, covers a minimum six-year (72 month) planning horizon including the year to date actuals (Jan-April 2013) and the current year's forecast (May-December 2013), often referred to as the bridge year (see diagram below). The company uses the comparison of capital budgets to actual performance to help determine if projects are on schedule and are consistent with on-going business planning requirements. **Thus providing good estimated in-service dates or closing patterns for projects is important and drives the change in rate base and impacts the income statement forecast of Allowance for Funds Used During Construction (AFUDC) and depreciation expense. In summary, your capital forecast must be verified against the "Checklist for Capital Forecasts", which includes the following and more:**

- Capital expenditures separated into CWIP, Removal Work In Progress (RWIP), and Customer Contributions in Aid of Construction (CIAC) if applicable object accounts
- Estimated in-service date or closing pattern aligned with the expenditure pattern
- Forecast for all parent work orders including those with a CWIP/RWIP balance after April 2013 accounting close,

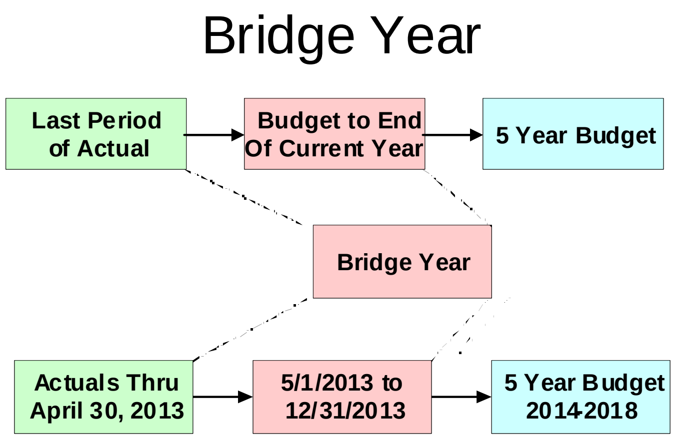
What is a Capital Budget?

The capital budget is a combination of: CWIP expenditures (spend to install an asset); RWIP expenditures (spend to remove an asset); and estimated in-service dates (or closing patterns), to arrive at the budgeted plant in-service (a major component of rate base). The budgeted plant in-service and related items (depreciation, AFUDC, etc) is an important input to cost of service studies used to support rate filings before various Commissions.

What is a Bridge Year?

The bridge year information is used to compute the beginning plant balances for the 2014 budget. Finally, capital forecasts support the estimation of the cash flow needs for the company into the future.

All of these reasons make it important that the capital budget accurately reflect the expenditures and expected in-service dates for the bridge year and upcoming budget period and is consistent with the requirements stated below



General Guidance

Capital budgets must meet the capitalization criteria and minimum levels of detail. In addition, proper documentation must include a description of each project and a financial explanation as to how expenditures were derived. Describe the benefits of the capital project, such as: productivity, process efficiency, reliability, safety, required due to law or covenant, etc. When writing descriptions and justifications for capital projects, please be as precise as possible. Refer to the *Capital Asset Accounting Policy - Capital Budget Principles* for additional information.

Support for routine projects requires a five-year expenditure and in-service history, or the assumptions used to develop the expenditure pattern and closing pattern. Closing patterns are developed to move dollars out of CWIP to plant in-service based upon their historic construction period for routines or completed phase of construction for non-routine projects. Construction completed in phases (more than one estimated in-service date per parent work order) has a closing pattern called "percent of work complete". Contact Capital Asset Accounting (CAA) if you need a project set up to close to plant in-service in phases for the budget. See the CAA Business Area Liaison list for contacts.

Capital budgeting data requirements for all projects are six years (i.e., 2013-2018) of monthly expenditures beginning with the remaining months of the forecast for the current bridge year (i.e., May to December 2013, assuming actual expenditures through April 2013), estimated in-service dates and closing patterns, where applicable. To capture total project expenditures, current forecasts must be reviewed and updated. In addition, actual CWIP balances need to be reviewed for estimated in-service dates, as well as any additional expenditure. Please see the "Requirements" section for more information.

Assumptions

Corporate Escalation Rates

Business areas, when preparing their six-year budgets (i.e., 2013-2018) of capital and O&M data, should NOT use "current year" dollars, but should use an appropriate escalation factor to cover costs for inflation. For general inflation increase estimates refer to the *Corporate Escalation Rates* published on the Corporate Budgeting Home Page. Other economic drivers may exist that require the use of more specific escalation factors for certain expenditures, such as nuclear fuel, steel or copper or long lead-time items such as power transformers. The support for all factors used should be well documented. Contact Supply Chain for relevant pricing information on many key categories.

Capital PC Refresh and IT Asset Management

Efficient use of personal computing assets enables Xcel Energy to leverage volume purchases, minimize support costs through product standardization, promote compatibility between IT assets and Xcel Energy's computing environment, monitor compliance with software licensing/data security, and maximize return on investment by carefully managing the lifecycle and use of these assets. . For additional information about IT management standards please refer to the following link: *Business Systems Standard*

IT Asset Management will determine an appropriate schedule for refreshing personal computers (PCs). At the start of the year, a list of the PCs to be refreshed during the year will be generated with a tentative schedule. The schedule will be maintained and updated during the course of the year.

Requirements for PCs outside of the refresh schedule will be closely scrutinized. The following justifications are acceptable for securing a new workstation: 1) hiring of a new employee, 2) PC lost or stolen, and 3) malfunctioning PC that is not repairable. Please refer to the section below for requesting and budgeting new PCs that are not included in the refresh project.

Budgeting for New IT Initiatives

All IT capital project budgets are budgeted by Business Systems and should not be part of the business areas' budgets. This includes software implementations, as well as hardware capital purchases for PCs, LANs and printers that meet the capital guidelines. Business areas should not budget for software/hardware projects. If you have any questions, contact Diane Prentis at 612-330-5744.

If you have a new IT initiative, such as a new application system, new support or a non-standard purchase, please contact Business Systems area directly to discuss your initiative. The contact list can be found under the following link Business Systems Contacts. This information is important so that Business Systems can budget and plan accordingly.

Overheads – E&S and A&G

CAA does not add E&S and Administrative and General (A&G) overheads to the expenditure stream for project budgets or forecasts as part of its budget processing. These project overheads are assumed to be ***included*** in the capital expenditure forecast provided. Each business area should assess the potential impact to their projects, especially for E&S charges for their large projects, and budget accordingly.

Allowance for Funds Used During Construction

Capital expenditures input by the business areas should **not** include AFUDC, which is calculated outside of CBS by CAA. CAA manages the actual accounting for AFUDC as well as the AFUDC associated with forecasted capital expenditures.

Environmental

Environmental capital expenditures associated with air, water and waste remediation should be budgeted in accordance with the *Environmental Budget Guidelines* published on the Corporate Budgeting Home Page. A clear distinction is made in the guidelines and Capitalization Policy identifying environmental charges that can be capitalized verses those that are required to be expensed.

Demand Side Management

Costs associated with Demand Side Management (DSM) or Conservation Investment Program (CIP) are not included in the capital forecast unless the resulting transaction involves a capital asset. Most DSM or CIP assets are accounted for as regulatory assets. These costs should be budgeted with a deferred parent work order, which is different than a capital parent work order. There are specific rules for these deferred work orders and they require Corporate Accounting approval. If you have any questions, contact Michael Hager at 303-571-7472.

Capital Help

If you need assistance from CAA, contact the CAA Hotline at 612-330-6490.

In addition, please refer to the *Capital Budget/Forecast-Parent Checklist* on the CAA website. This checklist should be used for the budget and every month a capital forecast is reviewed and modified to assure that there is no missing information in the data provided. This checklist will be used as a basis to measure how accurate and complete the capital budget/forecast you provide is.

Requirements

The total of capital expenditures for each of the next six years is significant and accordingly, we must prepare detailed budgets with transparency on where these amounts are being planned. The information below explains how to prepare your budgets to facilitate accurate budgeting and forecasting. CAA maintains the accounting policies and procedures and should be consulted, as needed, to insure proper accounting.

The primary balance sheet items that are impacted by **capital expenditures and estimated in-service dates or closing patterns** are CWIP, Plant In-Service, Accumulated Depreciation and Plant-Related Accumulated Deferred Income Taxes. Income statement influences include AFUDC and depreciation expense. The capital expenditures and dates are gathered across the business areas using CBS, Tamcast and Workbook and passed along to PowerPlant for the calculations of plant additions, book and tax depreciation, equity and debt AFUDC, and deferred income tax expense. The accurate forecasting of these amounts requires that the capital data (both spend and dates) be gathered and input into CBS, Tamcast or Workbook in accordance with the designed financial system and business process requirements.

Capital Expenditures

Accurate Monthly Expenditure Pattern - One of the critical responsibilities of the CFO organization is to ensure that sufficient cash is available to cover cash requirements. To accomplish this, the company must be able to derive meaningful cash flow forecasts from the financial budget and its monthly forecasts. Even though an expenditure is booked to capital; a dollar is spent and that dollar must be available to be paid out. The Financial Operations organization needs the pattern of expenditures from the budget or the forecast to assure that funds are available and consistent with long-term and short-term financing plans.

The cash flows or expenditures are provided when input into CBS, Tamcast or Workbook and these expenditures can be patterned or levelized, but should be representative of what one expects the monthly pattern of actual expenditures to be. This is important because the Company will plan its cash needs based on the expected cash outflows for construction. A large expenditure that was not anticipated could cause the company to incur higher than necessary carrying charges to obtain the funds than it may have if it could have planned for the large outflow of cash.

Separate Install Expenditures from Removal Expenditures - Capital expenditures cover both the capital dollars spent to install and remove capital assets. Expenditures associated with removal, as part of an asset retirement, should be budgeted as RWIP not CWIP. The importance of this is threefold:

1. RWIP does not accumulate AFUDC, whereas CWIP does,
2. RWIP is considered part of rate base for rate making when it is spent; CWIP is not part of rate base until it becomes an addition to plant in-service.
3. Estimated removal expense has been recovered from rate payers through the depreciation expense in the past, whereas CWIP will be recovered through depreciation expense in the future

If a project includes removing an existing asset before a new one is installed those removal expenditures should be budgeted as such. An estimate can be used to split the project expenditures and the removal estimate is entered into CBS, Tamcast or Workbook by using the RWIP JDE object accounts 740000-743350. Removal and installation expenditures can be tracked through the same parent work order. If significant salvage transactions are anticipated, they should be considered. It may be desirable to budget or forecast removal net of any salvage.

Alignment of Estimated In-Service Dates

Accurate estimated in-service dates are **critical** to ensuring that the financial systems (PowerPlant and CFM) know when to stop AFUDC, when to move the constructed asset from CWIP to plant in-service, and when to start book and tax depreciation. Also, for most projects, they are included in rate cases (rate base) when they are forecasted to move from CWIP to plant in-service.

For specific capital projects, the estimated in-service date must align with the expenditure pattern.

The in-service date is when commercial operation begins, such as when the line is energized or main pressurized. If a project has two or more phases of construction with different in-service dates, contact one of the CAA Business Area liaisons for assistance to set up a special closing pattern, called percent of work complete (see “Percent of Work Complete” section for more information).

The estimated in-service date is not the same as the estimated complete date. Typically, there are trailing expenditures, such as restoration, after the in-service date until the complete date. Each time a user updates their expenditures forecast, estimated in-service dates also need to be re-evaluated. It is also important to reevaluate and revise estimated in-service dates for projects expected to go in-service in the bridge year, 2013. The bridge year information computes the beginning plant in-service balances for the 2014 Budget. Inaccurate estimated in-service dates can negatively impact the forecast accuracy of depreciation expense, AFUDC, and plant in-service.

The general rules for the forecast expenditures alignment with dates:

- estimated in-service date **should not** be past the last month of the forecasted expenditures,
- there should be **no more than three months** (four months for Nuclear operations) of expenditures past the estimated in-service date (for large projects, the spend may go beyond three months),
- the estimated complete date cannot be before the estimated in-service date,
- the estimated complete date should be at the end of the last expenditure.

Routine projects are treated as short-term construction projects that are generally ready for service the month of the construction expenditures. For example, construction expenditures for routine projects like battery replacements at substations or general plant equipment forecasted in May will go into service in May for budget or forecast purposes.

For routine projects closing patterns must be aligned with the expenditures pattern. There are several closing patterns to choose from for routine projects that in-service a certain portion of the CWIP or RWIP balance (built from beginning actual CWIP/RWIP balance plus forecast spend for a project plus AFUDC on the CWIP portion) based on the number of months of construction or other percent.

Closing patterns are developed to move dollars out of CWIP to plant in-service based upon the estimated construction period. For these kinds of routines the rules set forth by closing patterns are used to move dollars from CWIP to plant in-service **until** the estimated in-service date is reached, then that is used to move dollars from CWIP to plant in-service for any additional expenditures. Please refer to the illustration below that shows the roll forward example of a routine project with CWIP activity:

Routine Parent work order with Est In-service Date 12/31/2013 and Closing Pattern "4 Mo Construct (40%)"

			Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
a		CWIP Beginning Balance	1,000,000	724,800	589,080	446,448	-	-
b		CWIP Forecasted Expenditures	200,000	250,000	150,000	300,000	50,000	25,000
c		AFUDC	8,000	7,000	5,000	5,000		
d	(a+b+c)	CWIP Balance Available to Close	1,208,000	981,800	744,080	751,448	50,000	25,000
e	(d x g)	CWIP Plant Additions (Closings)	(483,200)	(392,720)	(297,632)	(751,448)	(50,000)	(25,000)
f	(d + e)	CWIP Ending Balance	724,800	589,080	446,448	-	-	-
g		Closing Pattern (%)	40%	40%	40%	100%	100%	100%

Closing patterns are also used to move RWIP to accumulated depreciation reserve (these don't close to plant in-service, but impact net plant) based upon the estimated construction period. The rules set forth by closing patterns are used to move dollars from RWIP to reserve **until** the estimated completion date is reached, then that is used to move dollars from RWIP to reserve for any additional expenditures

Routine Parent work order with Est Completion Date 02/1/2014 and Closing Pattern "4 Mo Construct (40%)"

			Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
a		RWIP Beginning Balance	1,000,000	720,000	582,000	439,200	443,520	296,112
b		RWIP Forecasted Expenditures	200,000	250,000	150,000	300,000	50,000	25,000
c		AFUDC	-	-	-	-	-	-
d	(a+b+c)	RWIP Balance Available to Close	1,200,000	970,000	732,000	739,200	493,520	321,112
e	(d x g)	Depr Reserve Additions (Closings)	(480,000)	(388,000)	(292,800)	(295,680)	(197,408)	(321,112)
f	(d + e)	RWIP Ending Balance	720,000	582,000	439,200	443,520	296,112	-
g		Closing Pattern (%)	40%	40%	40%	40%	40%	100%

If you are forecasting a routine project for the entire forecast period (2013-2018) you may want to set the estimated in-service date past the forecast period, to avoid CWIP/RWIP balance to close 100 percent to plant within the forecast period; and it is suggested to set it no more than 5 years out from the last forecast period (i.e., 2023 for this budget). Please note that the estimated complete date cannot be more than 30 years from the estimated start date, and the estimated in-service date cannot be past the estimated complete date.

Percent of Work Complete – For the parent work orders with multiple phases of construction, a single specific estimated in-service date will not work. Either a percent or dollar amount should be identified for specific periods to move CWIP or RWIP to plant in-service or Accumulated Depreciation Reserve, respectively. The last phase of the project will use the estimated in-service date to close the remaining CWIP and estimated completion date the remaining RWIP. For those parent work orders that have CWIP and RWIP forecasted expenditures and have percent work complete closing patterns, the RWIP portion can be set up to close on the estimated complete date, the same dates as the percent set up for the CWIP portion, or a different pattern altogether. CAA will need to work with you on setting these up.

If parents are set up for each phase of the project related to the estimated in-service date one could avoid using percentage of work completed closing method.

1. ***Other-*** Do not budget or forecast spend on parent projects that have a status of cancelled, posted to Continuing Property Records (CPR), completed, in-service, or unitized. If you do use these parents to forecast expenditures, the actual in-service date will be used to move dollars from CWIP to Plant in-service in the forecast, which means forecasted spend will be in-serviced in the same month as the spend occurs, since the actual in-service date will be in the past.

Current Year Projects and Projects with CWIP Balances

All projects with actual CWIP balances must be reviewed for both spend and estimated dates. If the estimated in-service date is in the past, the project must be evaluated for either additional expenditures to be budgeted and estimated in-service date to be changed or the asset is used and useful and children work orders need to be in-serviced. Make every effort to have work orders in-serviced as soon as they are used and useful assets. It is important that the starting month of forecast has an accurate starting CWIP balance. Also, all open projects must be evaluated for expenditures for 2013 and beyond and the estimated in-service date must also be reviewed and updated if necessary.

Asset Retirements

Asset retirement is the removal or abandonment of an asset (or part of an asset if it meets the capitalization policy) from the field, and the removal of said asset from the CAA CPR. Because forecasted asset retirements are not recorded in any of the budgeting systems, planned (forecasted) large asset retirements need to be communicated to CAA during the budget process timeframe. It is important for both depreciation expense and tax depreciation to identify the retirements in the forecast.

The routine Transmission and Distribution (T&D) mass property retirements are forecasted based on historical data; however if there are any known large and unusual planned retirements, they need to be communicated to your CAA liaison in advance. See the CAA Liaison contacts for T&D at the end of the Capital Budgeting section

The Production asset retirements, in the budget, are processed based on planned retirements of individual large property groups (a whole property unit system or some major component of such system) or production plant. If there are plans to retire large production assets or any generating plants that may go off-line and become fully retired in the 2013-2018 cycle please provide plant name and projected date of decommissioning to Dave Amans in CAA (for contact information please refer to the CAA Liaison section at the end of this Capital Budgeting Instructions). The information from previous forecast is maintained by CAA and provided back to BA for the updates every budget/forecast cycle. CAA will then work with you to determine the specific asset(s) to retire in the forecast once information is gathered.

Legal Expenditures

Legal expenditures related to deferred or capital projects may warrant inclusion in the total expenditure of the project and are to be budgeted within the respective business area's deferred or capital budget. Business areas having capital projects or deferred expenditures, which may include legal expenses, must contact the General Counsel business area, who will provide the estimated budget for these projects to the business areas and will monitor legal expenditures associated with the project. Contact Deb Meuwissen at 612-215-4545 or Kimberly Hardy at 303-294-2010 if you have any questions.

Capitalization Policy

Every parent work order, upon initiation, is validated for consistency with the Capitalization Policy (i.e., accounting guidance applicable for actual book activity should be applied to budget and forecast data). This is true for every child work order as well. Occasionally, a project changes scope from the time it was budgeted to the time the actual work begins. If the actual work no longer meets the criteria for capitalization, the work cannot be capitalized even though the dollars reside in the capital budget. To avoid surprises between the budget and actual project expenditures, it is imperative that detail information be provided **before** initiation of the parent work order so that CAA can do the Capitalization Policy test quickly. **Please note that CAA policy is to validate projects within 3 days of receipt. During the busy budget season, CAA may need the full 3 days to complete validation, so please plan accordingly. Likewise, if hundreds of projects are sent at once to CAA to validate, turn around time may be longer.**

Level of Detail

All parent work orders budgeted within CBS and PowerPlant must identify the proper utility (i.e., electric, gas) and functional class (i.e., steam production, transmission) consistent with the FERC Uniform System of Accounts. The *Capital Expenditure Budget Requirements Matrix* included in the Appendices, summarizes the level of detail required. This level of detail is achieved in the budget by choosing the appropriate **Funding Project Type** when setting up your parent work order. This level of detail is required to identify depreciable from non-depreciable plant. It also captures plant accounts, which use different depreciation rates. This information must be budgeted for each operating company, as the approved depreciation rates vary by company.

The Regulatory department uses plant information for establishing electric and gas utility rates. There is a minimum level of detail at which projects cannot be further combined. All business areas must follow these requirements. For example, transmission substation work cannot be combined with the transmission line work. The matrix includes a listing of the applicable 300 level FERC accounts where such budgeted capital expenditures are typically closed to plant in-service. Also, see below for the detail required for parent work orders with special rate treatment.

Transmission Serving Generation or Distribution Serving Generation – For projects with interconnection facilities and network upgrades associated with generation facilities, specific funding project types should be used. **Please note that there are new funding project types for transmission serving generation work** (distribution serving generation can be set up based on business need) and this distinction must be made when setting up your projects for budgeting. This is important for ratemaking purposes. The distinction is made based upon the primary purpose for installing the transmission or distribution assets, rather than budget ownership. The budgeting guideline on this topic is included in the Appendices. Also the Transmission Interconnection & Network Glossary and Transmission Serving Generation Ownership Scenarios documents posted on the CAA web page (Transmission Serving Generation).

Parent Project Naming Conventions and Grandparent Summarization

Capital budgets and forecasts are used in rate case filings. It is important to consider how you name your project. Make sure that the parent project name provides important identifying information and is not misleading. Naming conventions may be used by your business area to facilitate easier identification of related projects, for instance, those related to a particular generating plant. Also, words that are descriptive help in understanding what the project is for. For example if parent description contains the key words indicating removal work (replace, remove, relocate, etc.) make sure that the RWIP dollars are forecasted. In addition, upon setting up your project you must choose a grandparent, which is another means to summarize types of projects. The grandparents are used to summarize and present CWIP and RWIP data in rate case schedules and testimony and should help explain the type of project. Projects related to each other, even if in different business segments, should be budgeted, have the same grandparent and dates should be in-sync. If you think you need a new grandparent, that is not currently in the CBS dropdown list, please choose the “Need New Grandparent” grandparent and then call your business area financial representative to discuss. The business area financial representative should then call the CAA liaison for the business area to discuss.

Separately Budget Capital Projects with Special Rate Treatment

Estimated in-service dates and expenditures affect the budgeted or actual revenue collected for rate rider projects as well as projects having special rate treatment (e.g., PSCo Transmission Cost Adjustment (TCA) also called Senate Bill 100). These projects are considered “Projects of Interest” and require prioritized reviews and updates. Therefore, CBS, Tamcast or Workbook should be updated with the most accurate estimates for the budget as well as monthly forecast updates, for both expenditures and estimated in-service dates. Each project must have separate parent work order numbers. CAA uses a unique Class Code tag on parent work orders to assure proper processing through rate case preparation. The specific Class Codes are provided by and approved by the rate areas. **Please contact the Rates and Regulatory department concerning all projects that qualify for special rate treatment.**

Any capital expenditures unrelated to the project (i.e., not subject to special rate treatment) must be budgeted to a separate parent work order. Thus, parent work orders requiring special rate treatment should have only the capital expenditures that are included in the approved regulatory orders or legislative mandates. Budget any removal expenditures associated with these projects in RWIP JDE object accounts 740000-743350, since removal expenditures do not qualify for any AFUDC calculations.

Type of Charges Incurred

Capital expenditures primarily include employee labor and benefits, contract labor, materials and other direct expenditures. AFUDC charges are calculated outside of CBS and should not be included as part of a users budgeted capital expenditures. AFUDC is added and becomes a component of the total construction charges included with the parent and child work orders within the Company's financial systems.

Reason Codes

Within the CBS system, the Company has established reason codes, which provide information about each parent work order that is used for internal reporting purposes to better understand and track expenditures. For example, the reason code, replace/refurbish should be applied to projects related to replacing worn-out or damaged or degraded equipment. These capital expenditures can then be distinguished from investments to serve new customers. While this information does not impact the forecast balance sheet or income statement, it provides useful information for management and is required. For more information on reason codes please see *Reason Code Definitions* published on the Corporate Budgeting Home Page.

Customer Contributions in Aid of Construction, Reimbursements, and Customer Advances

Non-refundable contributions in aid of construction (CIAC) (non-refundable CIAC, not customer advance or refundable CIAC) and other capital reimbursements from third parties are a common component of certain capital expenditures within the Delivery and Transmission business areas.

Non-refundable CIAC typically received for additional facilities installed for customers should be included in the capital expenditure forecast where applicable and can be supported with historical trends. Each business area needs to budget for non-refundable CIAC using JDE object accounts 733400-733460. Refundable CIAC or customer advances are not forecasted within CBS.

Customer reimbursements for relocating facilities to accommodate customers (other than Department of Transportation (DOT) customers), should be budgeted using object account 743150. For DOT customers, use object account 743160 to budget the credit.

Joint Ownership Share

The OpCo's have joint ownership capital projects, where the OpCo pays the full construction expenditures, then is reimbursed by the third party or joint owner, such as Comanche 3, Sherco 3, and Transmission CapX2020. With joint ownership projects, it is recommended to budget capital expenditures gross, the full amount, then record a credit to the appropriate joint ownership object account CWIP Joint Ownership 733340-733346 or RWIP Joint Ownership 743150-743160.

Capital Asset Accounting Business Area Liaisons

Budget Organization	CAA Liaison	Phone
Corporate Services	David Adams	303-294-2094
Transmission	Ray Hetherington	612-330-5565
Distribution	Becky Dean	303-294-2395
Energy Supply NSPM	Carol Callahan	612-330-7659
Energy Supply NSPW	Dave Amans	715-737-2495
Energy Supply PSCo	Kris Jenson	612-330-5583
Energy Supply SPS	Denise LeGault	303-294-2093
Nuclear Generation	Jake Miller	612-330-1959

Appendices

JDE Guidance

JDE Subledger Field

In order to charge out all costs, a subledger field must be entered on all budget lines using a Service Company JDE business unit. Since no JDE business unit can charge the Service Company, the subledger cannot be another Service Company JDE business unit.

There are no construction projects for the Service Company. For a shared asset (an asset used by more than one legal entity, for example 1800 Larimer building), you must contact Capital Asset Accounting and Keith Tanzyus at 303-294-2322 before setting up the project, as accounting for shared assets is a manual process.

For all operating company JDE business units, entering a subledger may not be required. The subledger must not be a Service Company JDE business unit. If a subledger is entered, this represents a cross-charge to the specified O&M or capital work order or JDE business unit within the same legal entity or to another legal entity. All capital projects require the use of an 8-digit subledger. If a subledger is entered, a subledger type of W must be entered.

For more information on JDE account coding, see *JD Edwards Training*.

JDE Subsidiary Field

Do not enter subsidiary values 97, 98 or 99 when budgeting or recording actuals in expense object accounts. These subsidiaries are automatically generated in JDE during the service billing process to identify incoming, outgoing or allocated indirect charges. For budget data this is completed within ALS. For the legal entity view and business area reporting, you can tell if charges received were incoming from or outgoing to another company or department, or indirectly allocated from the Service Company by the subsidiary field. Transactions that are **direct charged** (not allocated) from one department or company to another have a JDE subsidiary of 97 or 99 in the JDE account string. Transactions that are **indirectly allocated** from the Service Company have a JDE subsidiary of 98 in the JDE account string. The subsidiaries are automatically added to the account string, so **do not enter subsidiaries when deriving income statement account numbers**. Subsidiary values on actual balance sheet accounts provide additional account information such as location (i.e., city, state, etc.).

Incoming charges – Subsidiary 97 - Your specific JDE business unit was entered into the subledger field by another JDE business unit.
Outgoing charges – Subsidiary 99 – You entered another JDE business unit in the subledger field in order to bill the charges to that business unit.
Indirect charges – Subsidiary 98 – Allocated charges from the Service Company

Example of Direct Charge from Operating Company to Operating Company:

	Company	Business Unit	Object Acct	Subsidiary	Subledger	Amount
Original	NSPM	801598-NSPM	714000		803599-PSCo	700
Outgoing	NSPM	801598	714000	99	803599	-700
Incoming	PSCo	803599	714000	97	801598	700

Example of Allocated Charge from Service Company Using a 3-Digit Allocation Code:

	Company	Business Unit	Object Acct	Subsidiary	Subledger	Amount
Original	XS	601000	711142		121	1,000

Allocation	XS	601000	711142		121	-1,000
Allocation	XS	601000	711142	98	999232-PSCo	377.40
Allocation	XS	601000	711142	98	999233-SPS	140.70
Allocation	XS	601000	711142	98	699109-PSR	.70
Allocation	XS	601000	711142	98	999011-1480	.70
Allocation	XS	601000	711142	98	999230-NSPM	414.10
Allocation	XS	601000	711142	98	999231-NSPW	66.30
Allocation	XS	601000	711142	98	498725-Reddy	.10
Outgoing	XS	50	Revenue			-1,000
Indirect Chg	PSCo	999232	711142	98	601000	377.40
Indirect Chg	SPS	999233	711142	98	601000	140.70
Indirect Chg	PSR	699109	711142	98	601000	.70
Indirect Chg	1480	999011	711142	98	601000	.70
Indirect Chg	NSPM	999230	711142	98	601000	414.10
Indirect Chg	NSPW	999231	711142	98	601000	66.30
Indirect Chg	Reddy	498725	711142	98	601000	.10

Note: These examples exclude inter-company receivable/payable entries that are also automatically generated by JDE during service billing.

FERC, Utility, and State Jurisdiction Accounting

Each business area is responsible for the appropriate utility (electric, gas, thermal and non-utility) and FERC designation on their business areas' budgeted O&M dollars. The JDE business unit and object account determine the utility and FERC account. Each JDE business unit and object has category codes attached to it that determine which utility and FERC account the account string translates to. Here is a brief description of some of the main category codes:

Utility Category Codes
Account category code 20 – electric, gas, thermal, non-utility and common (if this field is populated it overrides BU category code 3)
BU category code 3 – electric, gas, thermal, non-utility and common

FERC Category Codes
Account category code 21 – FERC account (if this field is populated it overrides BU category code 21)
BU category code 21 – FERC account

Other Category Codes
BU category code 4 – A&G, operating, maintenance, etc.
BU category code 5 – functional class such as distribution, production, sales, gas storage, etc.
BU category code 6 – location code which helps determine the applicable state jurisdiction

For any costs directly attributed to a specific jurisdiction, ensure the location code (BU category code 6) on the JDE business unit is correct (if there is no subledger). If there is a subledger, verify the location code on the subledger is correct.

For additional information on translating JDE account strings to FERC account and utility, please see the document titled *JD Edwards Regulatory Ledger Training* on the Regulatory Accounting Training webpage.

Capital Expenditure Budget Requirements Matrix

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
Electric Utility			
Steam Production	◦ Land and land rights including water rights	◦ Land and land rights including water rights	◦ 310.0 – Land ◦ 310.1 – Land Rights
	◦ Total assets by facility except for a few that are separated by unit due to different depreciation rates, such as Sherco and Comanche	◦ Depreciable assets by facility, except where individual units are jointly-owned by third parties or use different depreciation rates (Sherco 3 and Comanche 3)	◦ 311 – Structures & Improvements ◦ 312 – Boiler Plant Equipment ◦ 314 – Turbogenerator Unit ◦ 315 – Accessory Electric Equipment ◦ 316 – Miscellaneous Power Plant Equipment
Nuclear Production	◦ Total assets by facility	◦ Land and land rights	◦ 320.0 – Land ◦ 320.1 – Land Rights
		◦ Depreciable assets by facility	◦ 321 – Structures & Improvements ◦ 322 – Reactor Plant Equipment ◦ 323 – Turbogenerator Unit ◦ 324 – Accessory Electric Equipment ◦ 325 – Miscellaneous Power Plant Equipment
Nuclear Fuel	◦ Total assets by facility	◦ Total assets by facility	◦ 120.2 – Nuclear Fuel Materials and Assemblies – Stock ◦ 120.3 – Nuclear Fuel Assemblies in Reactor ◦ 120.4 – Spent Nuclear Fuel
Hydro Production	◦ Total assets with no facility separation	◦ Land and land rights	◦ 330.0 – Land ◦ 330.1 – Land Rights

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
		◦ Depreciable assets by facility	◦ 331 – Structures & Improvements ◦ 332 – Reservoirs, Dams & Waterways ◦ 333 – Waterwheels, Turbines & Generators ◦ 334 – Accessory Electric Equipment ◦ 335 – Miscellaneous Power Plant Equipment ◦ 336 – Roads, Railroads & Bridges
Other Production	◦ Land and land rights	◦ Land and land rights	◦ 340.0 – Land, ◦ 340.1 – Land Rights
	◦ Depreciable assets by facility	◦ Depreciable assets by facility	◦ 341 – Structures & Improvements ◦ 342 – Fuel Holders, Producers & Accessories ◦ 343 – Prime Movers ◦ 344 –Generators ◦ 345 – Accessory Electric Equipment ◦ 346 – Miscellaneous Power Plant Equipment
Transmission	◦ Land and easements	◦ Land ◦ Easements	◦ 350 – Land ◦ 350 – Land Rights
	◦ Substations	◦ Substations	◦ 352 – Structures & Improvements ◦ 353 – Station Equipment
	◦ Substations	◦ Substations - Transmission Serving Generation	◦ 352 and 353
	◦ Lines	◦ Lines	◦ 354 – Towers & Fixtures ◦ 355 – Poles & Fixtures ◦ 356 – Overhead Conductor & Devices ◦ 357 – Underground Conduit ◦ 358 – Underground Conductor & Devices ◦ 359 – Roads & Trails
	◦ Lines	◦ Lines – Transmission Serving Generation	◦ 354 - 358
Distribution	◦ Land and easements	◦ Land	◦ 360 – Land

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
(By state)		◦ Easements	◦ 360 – Land Rights
	◦ Substations	◦ Substations	◦ 361 – Structures & Improvements
			◦ 362 – Station Equipment
	◦ Lines	◦ Lines	◦ 364 – Towers & Fixtures
			◦ 365 – Overhead Conductor & Devices
			◦ 366 – Underground Conduit
			◦ 367 – Underground Conductor & Devices
	◦ Other	◦ Other	◦ 368 – Line Transformers
			◦ 369 – Services
			◦ 370 – Meters
			◦ 371 – Installs on Customer's Premises
		◦ Street Lighting	◦ 373 – Street Lighting & Signal Systems
General Property	◦ Non-depreciable	◦ Intangibles	◦ 301 – Organizational Costs
			◦ 302 – Franchises & Consents
		◦ Land	◦ 389 – Land
		◦ Easements	◦ 389 – Land Rights
	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ Buildings	◦ Buildings	◦ 390 – Structures & Improvements
	◦ Transportation Equipment	◦ Transportation Equipment	◦ 392 – Transportation Equipment
			◦ 396 – Power Operated Equipment
	◦ General Equipment (Includes communication for PSCo and SPS)	◦ Furniture & Equipment	◦ 391 – Office Furniture & Equipment
		◦ Network Equipment	◦ 391 – Office Furniture & Equipment
		◦ Tools & Equipment	◦ 393 – Stores Equipment
			◦ 394 – Tools, Shop & Garage Equipment
			◦ 395 – Laboratory Equipment
			◦ 398 – Miscellaneous Equipment
	◦ Communication Equipment (for the NSPM	◦ Communication Equipment	◦ 397 – Communication Equipment

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
	and NSPW only)		
		◦ Telecommunication Equipment	◦ 397 – Telecommunication Equipment
Gas Utility			
Manufactured Production	◦ Total Assets	◦ Land ◦ Depreciable assets	◦ 304 – Land ◦ 305 – Structures & Improvements ◦ 311 – Liquefied Petroleum Gas Equipment ◦ 320 – Other Equipment
Gathering Production	◦ Total Assets (PSCo Only)	◦ Easements ◦ Depreciable assets	◦ 325.4 –Rights-of-way ◦ 327 – Field Compressor Station Structures ◦ 328 – Field Measuring & Regulating Station Structures ◦ 329 – Other Structures ◦ 332 – Field Lines ◦ 333 – Field Compressor Station Equipment ◦ 334 – Field Measuring & Regulating Station Equipment
Extraction Production	◦ Total Assets (PSCo Only)	◦ Land and easements ◦ Depreciable assets	◦ 340.1 – Land, ◦ 340.2 – Land Rights ◦ 341 – Structures & Improvements ◦ 342 – Extraction & Refining Equipment ◦ 343 – Pipe Lines ◦ 344 – Extracted Product Storage Equipment ◦ 345 – Compressor Equipment ◦ 346 – Gas Measuring & Regulating Equipment ◦ 347 – Other Equipment
Underground Storage	◦ Total Assets	◦ Land and easements ◦ Depreciable assets	◦ 350.1 – Land, ◦ 350.2 –Rights-of-way ◦ 352.1 – Storage

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
			Leasehold and Rights ◦ 352.2 – Reservoirs ◦ 352.3 – Non-recoverable Natural Gas ◦ 353 – Lines ◦ 354 – Compressor Station Equipment ◦ 355 – Measuring & Regulating Equipment ◦ 356 – Purification Equipment
Other Storage	◦ Total Assets	◦ Land and easements ◦ Depreciable assets	◦ 360.1 – Land ◦ 360.2 – Land Rights ◦ 361 – Structures & Improvements ◦ 362 – Gas Holders ◦ 363 – Purification Equipment ◦ 363.1 – Liquefaction Equipment ◦ 363.2 – Vaporizing Equipment ◦ 363.3 – Compressor Equipment ◦ 363.4 – Measuring & Regulating Equipment ◦ 363.5 – Other Equipment
Transmission (By state)	◦ Land and easements ◦ Depreciable Assets	◦ Land ◦ Easements ◦ Depreciable assets	◦ 365.1 – Land ◦ 365.1 – Land Rights, ◦ 365.2 – Rights of Way ◦ 366 – Structures & Improvements ◦ 367 – Mains ◦ 368 – Compressor Station Equipment ◦ 369 – Measuring & Regulating Station Equipment ◦ 370 – Communication Equipment ◦ 371 – Other Equipment
Distribution (By state)	◦ Land and easements	◦ Land ◦ Easements	◦ 374 – Land ◦ 374 – Land Rights

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
	◦ Mains, TBS, Meters and Regulators	◦ Mains and TBS; includes services	◦ 375 – Structures & Improvements ◦ 376 – Mains ◦ 380 – Services
		◦ Meters and Regulators	◦ 381 – Meters (includes 382 – Meter Installations, 383 – Regulators, and 384 – Regulator Installations) ◦ 387 – Other Equipment
General Property	◦ Non-depreciable	◦ Intangibles	◦ 301 – Organizational Costs, ◦ 302 – Franchises & Consents
		◦ Land	◦ 389 – Land
		◦ Easements	◦ 389 – Land Rights
	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ Buildings	◦ Buildings	◦ 390 – Structures & Improvements
	◦ Transportation Equipment	◦ Transportation Equipment	◦ 392 – Transportation Equipment ◦ 396 – Power Operated Equipment
	◦ General Equipment (Includes communication for PSCo only)	◦ Furniture & Equipment	◦ 391 – Office Furniture & Equipment
		◦ Network Equipment	◦ 391 – Office Furniture & Equipment
		◦ Tools & Equipment	◦ 393 – Stores Equipment ◦ 394 – Tools, Shop & Garage Equipment ◦ 395 – Laboratory Equipment ◦ 398 – Miscellaneous Equipment
	◦ Communication Equipment (Includes communication for NSPM and NSPW only)	◦ Communication Equipment	◦ 397 – Communication Equipment
	◦	◦ Telecommunication Equipment	◦ 397 – Telecommunication Equipment
Thermal Utility			
Production	◦ Land	◦ Land	◦ 310 – Land
	◦ Depreciable Assets	◦ Depreciable assets	◦ 311 – Structures &

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
			Improvements ◦ 312 – Boiler Plant Equipment ◦ 315 – Accessory Electric Equipment ◦ 316 – Miscellaneous Power Plant Equipment
Distribution	◦ Depreciable assets	◦ Depreciable assets	◦ 376 – Mains ◦ 378 – Measuring & Regulating Equipment – General ◦ 380 – Services ◦ 381 – Meters ◦ 382 – Meter Installations
General Property	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ General Equipment	◦ Tools & Equipment	◦ 391 – Office Furniture & Equipment ◦ 393 – Stores Equipment ◦ 394 – Tools, Shop & Garage Equipment ◦ 395 – Laboratory Equipment ◦ 398 – Miscellaneous Equipment
Non-Utility			
Production & Other	◦ Non-depreciable assets	◦ Non-depreciable assets	◦ 121 – Non-utility Property
	◦ Depreciable assets	◦ Depreciable assets	◦ 121 – Non-utility Property
Common Utility			
General Property	◦ Intangibles	◦ Intangibles	◦ 301 – Organizational Costs ◦ 302 – Franchises & Consents
		◦ Land	◦ 389 – Land
		◦ Easements	◦ 389 – Land Rights
	◦ Software	◦ Software	◦ 303 – Computer Software
	◦ Buildings	◦ Buildings	◦ 390 – Structures & Improvements
	◦ Transportation Equipment	◦ Transportation Equipment	◦ 392 – Transportation Equipment ◦ 396 – Power Operated

Utility/Functional Class	CFM: Financial Forecasting (Plant Chart of Accounts)	CBS & PowerPlant Budget Requirements (Parent Work Order)	In-Service Plant: FERC Accounts
			Equipment
	◦ General Equipment	◦ Furniture & Equipment	◦ 391 – Office Furniture & Equipment
		◦ Network Equipment	◦ 391 – Office Furniture & Equipment
		◦ Tools & Equipment	◦ 393 – Stores Equipment
			◦ 394 – Tools, Shop & Garage Equipment
			◦ 398 – Miscellaneous Equipment
	◦ Communication Equipment	◦ Communication Equipment	◦ 397 – Communication Equipment
		◦ Telecommunication Equipment	◦ 397 – Telecommunication Equipment

Transmission/Distribution Serving Generation Budgeting Guideline

Questions to Ask:

What is the primary purpose of a connection to the transmission or distribution network or an upgrade to the network?

If the answer is generation (a.k.a production), then the project should be set up as a Transmission Serving Generation project or as a Distribution Serving Generation project. The setup of the project function should NOT be determined by who has budget responsibility for the project. The parent project should be set up with the funding project type of Transmission or Distribution (Lines or Subs) Serving Production.

If it is a Transmission Serving Generation or Distribution Serving Generation project, who has budgetary responsibility for the project?

Budget responsibility does not change the classification of the project as Transmission (or Distribution) Serving Generation.

- **If Energy Supply owns the generation assets**
  Energy Supply should have budget responsibility for the Interconnection project; the project will be classified on the books as a Transmission (or Distribution) asset; and for ratemaking purposes, it will be treated like production plant.

  Any Network Upgrades may be budgeted by either Energy Supply or Transmission (the departments must come to an agreement).

- **If an Independent Power Producer owns the generation assets**
  Transmission has the budget responsibility for the Interconnection project (there will be a Contribution in Aid of Construction paid by the Independent Power Producer offsetting the capital cost in the budget); the project will be classified on the books as a Transmission (or Distribution) asset; and for ratemaking purposes it will be treated like production plant.

  Any Network Upgrades should be budgeted by Transmission. Again, the Independent Power Producer will pay a CIAC.

- **If Energy Supply owns the generation assets, but an Independent Transmission Provider owns the interconnection project**
  Energy Supply should budget the project and will pay a CIAC to the Independent Transmission Provider; the project will be classified on the books as a Transmission (or Distribution) asset; and for ratemaking purposes it will be treated like production plant.

  If Network Upgrade assets will be owned by Xcel Energy, then those upgrades may be budgeted by either Energy Supply or Transmission (the departments must come to an agreement).

  If Network Upgrade assets will be owned by the Independent Transmission Provider, then those upgrades should be budgeted by Energy Supply (who will pay a CIAC to the Independent Transmission Provider).

Glossary of Terms and Acronyms

A&G, Administration and General.

A&G Capital Overhead. Administrative and General is a capital overhead that assigns the labor from certain departments that are considered general office functions to capital projects. The amount is based upon a biennial study that looks at the budgeted labor for these departments and the amount of time they dedicate to capital functions.

ALS. Allocation Ledger System - processes CBS data using service billing functionality similar to JDE and presents the legal entities' O&M and Capital budgets in an allocated view. Managerial view data is also maintained in ALS for reporting.

AFUDC. Allowance for Funds Used During Construction represents the cost of financing or funding a project before it is in its revenue-generating phase. Using a FERC specified formula, AFUDC is calculated and added to the capital project and at the same time is recognized as either income (the equity component) or an offset to interest expense (the debt component). When the project goes into service the capitalized cost of the debt and equity is part of depreciation expense, which is a component of the customer's rate.

Blanket Child Work Orders. The blanket child work orders are a summation of many smaller dollar, high volume capital jobs that are grouped together because of the similar nature of the work, i.e., meters or new business blankets.

Bridge Year. Refers to the current year in which there are some actuals and some forecast months. It is a term used in the capital budgeting process to reference the year that precedes the budget years. The bridge year information is used to compute the beginning plant balances for the first year of the budget, and thus is an important component of the budget.

BTE. Business Technology Executives are within the Business Systems organization and are assigned to each business area. Representative names are included in the Budget Instructions in the applicable sections.

Business Area. Refers to the areas within the Company that operate as an organizational unit. Examples are: Transmission Energy Supply; Distribution Operations; Corporate Services; etc. For internal reporting, it is an aggregate of JDE Business Units.

CAA. Capital Asset Accounting

CBS. The CompetiSoft Budgeting System - the corporate input tool used for preparing O&M and Capital budgets.

CFM. The CompetiSoft Forecasting Model - the corporate tool used for financial planning/forecasting.

CFO Chief Financial Officer

Child Work Order. This is the work order where the actual jobs costs are accumulated. These are often called just work orders without the prefix "child". The forecasting does not occur at the child work order level.

CIAC. Contribution in Aid of Construction.

CIP. Conservation Investment Program

Closing Pattern. Developed for forecast purposes to move dollars out of CWIP to plant in-service based upon their historic construction period for routines or completed phase of construction for non-routine projects.

Cost Components. A group of object accounts or categories of costs. Examples include employee expenses, contract labor and consulting costs.

CWIP. Construction Work in Progress is the spend to install an asset. The balance represents construction work not yet completed but in process.

Deferred Work Orders. Used to capture costs associated with regulatory assets, regulatory liabilities deferred assets and deferred liabilities. For additional information contact Regulatory Accounting.

DSM. Demand Side Management

***E&S Overhead*.** Engineering and Supervision Overhead is an overhead that is used to allocate indirect costs associated with construction from the engineering departments.

FERC. Federal Energy Regulatory Commission

ISP. Information Service Provider

In-Service Date. In general, this is the date upon which the construction project has been turned over from the construction manager to the operations manager. In the financial forecast process, this date is called the estimated in-service date and it triggers moving the dollars from CWIP to plant in-service, AFUDC to stop and book/tax depreciation to start (see *Capital Asset Accounting Policy - Capital Budget Principles*).

JDE. JD Edwards – the general ledger system used by the company

JDE Business Unit. JDE Business Unit is a six-digit number that represents the department or department structure. For some departments the capital work is assigned a different JDE Business Unit than the operating work. In PowerPlant, this number is shown in the department field.

NPT. Non-productive time

NSPM. Northern States Power Company – Minnesota

NSPW. Northern States Power Company – Wisconsin

O&M. Operating and Maintenance

OpCo. Operating Company – includes the four operating companies in the Xcel Energy holding company system. They are NSPM, NSPW, PSCo, and SPS.

Percent of Work Complete. A closing pattern developed for a specific parent project work order that has multiple construction in-service phases. The pattern is developed based on input from the project owner, including the forecasted CWIP balance and the dates of an in-service phase and either the amount to in-service or percent of the CWIP balance to in-service.

PSCo. Public Service Company of Colorado

PTO. Paid time off

Parent Work Order. A parent work order is the terminology used by the JD Edwards system and is synonymous with the term Funding Project used in the PowerPlant system. It is the level at which the budget/forecast data is gathered and reported. Actual project expenditures for capital work are never recorded to the parent work order, but may be summed up and reported at the parent wok order level. Many child work orders can be grouped under one parent work order.

***Routine Parent Work Order*.** A capital project that contains ready-made or quickly installed capital assets such as transportation equipment, network equipment, distribution meters, line transformers, or substation batteries. Previously these were referred to as blanket parent work orders.

RWIP. Removal Work In Progress is the spend to remove an asset. The balance represents removal work not yet completed but in process.

SPS. Southwestern Public Service Company

T&D. Transmission and Distribution

Vacancy Rate. Refers to an annualized rate that is budgeted to account for positions that are estimated to be open at any point during the year.

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Xcel Energy			
Case No.:	PU-12-813		
Response To:	North Dakota Public Service Commission	Data Request No.	NDPSC-6-016
Requestor:	Snavely King Majoros & Associates		
Date Received:	April 2, 2013		

Question:

Please refer to page 1, lines 22-26 of the Direct Testimony of Stephen R. Foss. Please (1) describe and explain in detail NSPM's system planning and capital budgeting processes for its Distribution, Transmission, and Energy Supply business units, (2) provide documentation of NSPM's planning and budgeting procedures and guidelines, and (3) provide a map or maps of NSPM's system showing the location of distribution and transmission planning load centers.

Response:

Please refer to Company witness Anne Heuer's Direct testimony pages 5 through 10 for discussion related to the Company's O&M and capital budget development process. In addition, Corporate Budget Instructions for budgeting operating and maintenance (O&M) and capital expenses for Xcel Energy are provided as Attachment A in the Company's response to information request NDPSC-1-019.

(1) Describe and explain in detail NSPM's system planning and capital budgeting processes for its Distribution, Transmission, and Energy Supply business units,

Distribution:

Distribution Operations has a well-defined process for identifying, ranking and budgeting electric line and distribution substation projects. The key steps necessary to ensure the preparation of a comprehensive capital budget are summarized as follows. Engineering and operations personnel identify potential problems or risks on the system and solutions. "Risks" are potential detrimental impacts or threats to safety, the quality/reliability of our service, environmental quality, our ability to meet our legal obligations, or our financial standing. These identified risks drive the need for initiatives to address the risks. These initiatives, in turn, often require capital expenditures. In the capital budgeting process, potential "solutions" or "mitigations" are essentially "projects;" *i.e.*, work to be performed that will mitigate a certain risk, or set of risks. These projects are the focus of the capital budget process. Projects are screened and evaluated against each other based on their costs, how effectively they address certain risks, and how critical the risks are. The evaluation or scoring of risks, mitigations and solutions is only an intermediate step. The ultimate goal is to determine which projects will be funded and at what levels.

Each risk and mitigation is reviewed for accuracy, completeness and reasonableness. As each risk and solution is considered, it is scored based on certain criteria, likelihood of occurring, and the consequences of not addressing it. All potential mitigations are ranked or prioritized. After the ranking is completed, business leadership reviews the list, the level of risk associated with the various projects, as well as capital levels based on financial criteria. Projects chosen to be funded are assigned a capital project number based on the type of work. These capital projects are classified as either "specific" or "routine." Capital project numbers for large pools of small projects (e.g., underground extensions, overhead services, etc.) are automatically tied to closing patterns based on the attributes of the work. For larger individual projects, in-service dates are assigned. Project managers then forecast expenditures based on the particulars of a project and its projected in-service date. All capital projects that are included are reviewed and approved, both at the business area level and at the corporate level.

Transmission:

The Capital budget for Transmission begins with the Planning Group identifying new projects to be added for consideration to the new five year budget. The projects are entered into the Tamcasting system along with the description, need and benefits of the project. At minimum, a scoping level estimate is required to be done for the proposed budget and the project must have gone through the first level of constructability meetings to justify the need for the project. All projects in the current approved budget are "refreshed" by the engineering and planning groups who provide the best available data for the project for this budget cycle. All data is compiled and reviewed in detail by project by Project Management and Portfolio Delivery to further vet the need, amount and the timing of the proposed projects. Existing projects that have changed significantly in scope or forecast may require further scrutiny during a "challenge session" to take a deeper look at the details of the project and its associated forecast. A second layer of management review is done at the Vice President of Transmission level before the budget is submitted for corporate review and approval. Projects meeting the criteria for Investment Review Committee or Board approval are presented as part of the budget process.

Energy Supply:

There are multiple factors driving Energy Supply capital requirements. The most significant factors include safety, generation load growth, environmental regulations, and unit operational condition.

Each year, projects submitted by the plants are evaluated and ranked according to their financial and operational merits, such as impact on safety, availability and environmental compliance. Each capital project is reviewed and prioritized using multiple criteria, including safety, financial merit (such as Present Value of Revenue Requirements) and operational factors (such as impact on Unplanned Outage Rate, equipment condition, environmental compliance and/or regulation). Projects that are evaluated include those that may be completed in a single year as well as those that will require multiple years to execute and complete.

A ranked list of projects is evaluated against the available capital budget for the next year, as well as the planned unit outage schedule for the next several years and known regulatory factors, such as new environmental regulations. This process allows the Company to develop a capital plan that covers a five-year period, thus allowing the Company to utilize the five-year capital expenditures and estimated in-service dates in the capital budget process. As this list of projects is finalized in each jurisdiction (NSPM, NSPW, PsCo and SPS), it is reviewed and approved by Plant Directors, General Managers, Vice Presidents and Xcel Energy's Financial Council.

Capital budgets are established at least 12-18 months prior to their execution. Part of the project development process includes the identification of key schedule dates and budgetary milestones. Once a capital project has been approved for execution, it is assigned to a Project Manager ("PM"). The PM is responsible for working with the plant to review and more fully develop the schedule and monthly cash flow requirements for the assigned project. The PM will typically contact vendors and contractors to firm up cost and schedule data and begin engineering and purchasing activities. As the PM works through the project details, they develop detailed cash flows and schedules for the project. Those schedules and cash flows are entered into corporate accounting. Monthly review activities include verifying that planned activities have been undertaken as scheduled. If cost or schedule variances arise, they are discussed at the monthly project meetings along with corrective actions. As the project is completed and placed in-service, the PM follows close-out activities to update plant drawings and procedures.

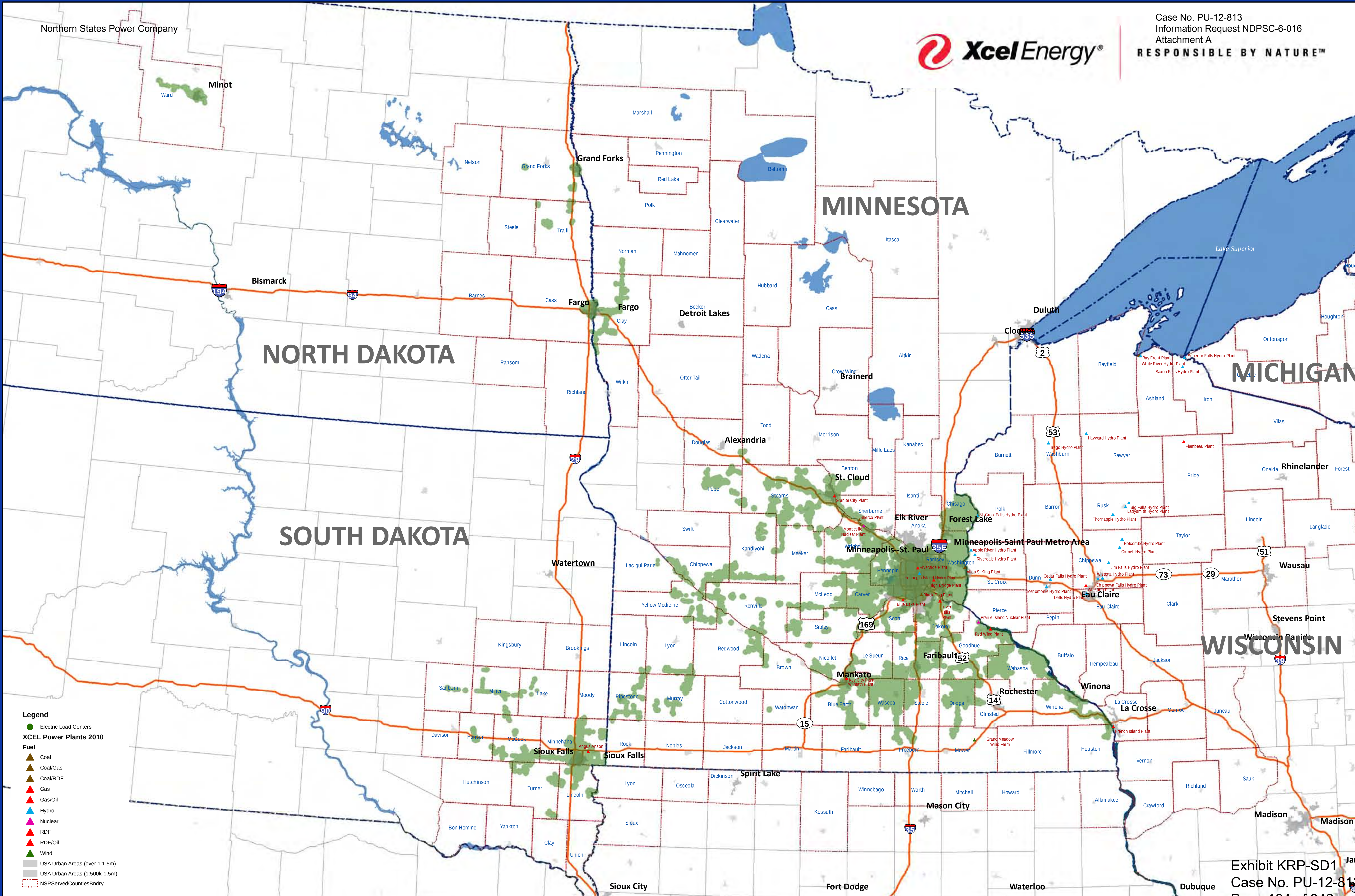
(2) Provide documentation of NSPM's planning and budgeting procedures and guidelines,

Please see Attachment A to the Company's response to information request NDPSC-1-019. The budget instructions include the schedule and describe the guiding principles used to establish the corporate O&M and capital budgets.

(3) Please see Attachment A for a map of NSPM load centers.

Witness:	Stephen Foss
Preparer:	Greg Robinson/Mark Wehlage
Title:	Manager/Manager
Department:	Financial Planning & Analysis/Transmission Planning
Telephone:	612-215-4631/612-330-7631
Date:	May 3, 2013

XCEL ENERGY INC. NSP LOAD AREAS



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Xcel Energy			
Case No.:	PU-12-813		
Response To:	North Dakota Public Service Commission	Data Request No.	NDPSC-11-005
Requestor:	Snavely King Majoros & Associates		
Date Received:	May 22, 2013		

Question:

Please refer to NSP response to NDPSC-6-016, Part (1). (1) With regard to the referenced "detrimental impacts or threats to safety, the quality/reliability of [NSP], environmental quality" of NSP's distribution system, please provide (A) a list of the quantitative factors, criteria, indices, etc. used to measure the impacts and/or threats to the distribution system's safety, quality, reliability, and environmental quality and (B) all documentation of and guidelines for the distribution system planning process that is the basis for NSP's distribution capital and O&M budgeting process. (2) With regard to the identification of "new projects to be added for consideration to the new five year budget" for NSP's transmission system, please provide (A) a list of the quantitative factors, criteria, indices, etc. used to identify new projects and to measure the "need and benefits" of new transmission projects and (B) all documentation of and guidelines for the transmission system planning process that is the basis for NSP's transmission capital and O&M budgeting process.

Response:

In addition to the information provided below, please also see the Company's 2014 – 2018 O&M Budget and Capital Budget Instructions submitted as Attachment B to NDPSC-1-019.

1(A). The quantitative factors and criteriaused to measure the impacts and/or threats to the distribution system's safety, quality, reliability, and environmental quality are as follows:

- **Percent Overload** – loading of system devices focusing on those devices where the expected load is projected to exceed the device rating (calculated at system peak condition)
- **Type of Overload** – system intact or under loss of any one element (1st contingency status)

- **Probability of Occurrence** – how likely the event is to occur that would lead to overloads, customers out, and/or other potential risks.
- **MVA at Risk** – the amount of load that cannot be redirected or "backed-up" given a loss of that asset.
- **Customer Minutes Out (CMO)** – upon loss of any distribution element (such as: Substation Transformer, Feeder, line transformer, pole, switch, breaker etc.) causing overload of back-up facilities or an immediate outage, determine the projected impact on number of customers who may be without power during this scenario. along with projected time to respond with a remedial action to restore service to customers impacted. This is a calculation of number of customers expected to be out of service by the event multiplied by the estimated length of the outage in minutes.
- **Performance History** – for reliability focused projects, known recent failure history and/or overall reliability performance and impacts on customers served. Within this category, multiple events and/or high frequency occurrences leading to customer complaints and/or possible PUC complaints.
- **Inspection Results** – for asset health (device replacements), results of any routine and/or spot inspections are considered.
- **System Efficiency** – evaluation of projects and their impacts on system efficiency taking into account reduced energy losses.
- **Legal Obligation** – examples include obligation to extend service to customers within our service territory, adherence to franchise agreements with the cities we serve (e.g. relocation of facilities to accommodate road projects), etc.
- **Safety** – consider identified risks to either the public or employee safety that cannot be immediately rectified.
- **Environmental Quality** - risks to the environment such as soil contamination are considered.

1(B). Please see Attachment 1 for "Principles of Distribution Planning," for documentation of and guidelines for the distribution system planning process.

2 (A). Please see Attachment 2 for NSP's Transmission Planning Standards (TPL). NSP also uses factors such as losses and present value analysis to compare alternatives that address deficiencies identified when planning the NSP transmission system. Additional quantitative factors and criteria used to measure the impacts and/or threats to the transmission system's safety, quality, reliability, and environmental quality include:

- **Overloads** – loading of system devices must stay below their equipment ratings. NSP focuses on those devices where the expected load is projected to exceed the device rating (calculated at system peak condition or other maximum loading conditions such as power high transfers)

- **Voltage** – the transmission system must be operated within a bandwidth for acceptable voltage. Contingencies/outages that cause voltages to climb too high or go to low need to be addressed. This is analyzed over a range of projected system operating conditions.
- **Type of Outage**– system intact or under loss of any one element (1st contingency status), or multiple elements as required to be evaluated in NERC Transmission Planning Standards. Selection of the best project to mitigate overloads and voltage deviations is done utilizing reliability criteria, future projected changes, and knowledge of the area.
- **Performance History** – for reliability focused projects, known recent failure history and/or overall reliability performance and impacts on customers served. Within this category, multiple events and/or high frequency occurrences leading to customer complaints and/or possible PUC complaints.
- **Inspection Results** – for asset health (device replacements), results of any routine and/or spot inspections are considered.
- **System Efficiency** – evaluation of projects and their impacts on system efficiency taking into account reduced energy losses.
- **Legal Obligation** – examples include obligation to extend service to customers within our service territory, or obligations under FERC approved tariffs
- **Safety** – consider identified risks to either the public or employee safety that cannot be immediately rectified.
- **Environmental Quality** - risks to the environment such as soil contamination and many other potential environmental impacts such as tree, plant or species impact, number of landowners impacted by transmission project options, and other environmental factors

2 (B). Along with the guidelines provided in our response above, please see Attachment 3 for NERC's TPL standards. Consistent with FERC orders, NSP is required to plan its transmission system in accordance with the NERC TPL reliability standards.

The planning criteria for capital projects can result in additional O&M costs. For example, increased maintenance could result from adding transmission equipment to our fleet that must be maintained consistent with NERC reliability standards. As another example, our planning analysis could result in a transformer needing its tap ratio adjusted so that voltage stays within guidelines in a particular area.

Preparer:	Joseph Mansur/Mark Wehlage
Title:	Manager/Manager
Department:	Distribution Performance/Transmission Planning
Telephone:	651-229-2286/612-330-7631
Date:	June 6, 2013

PRINCIPLES OF DISTRIBUTION PLANNING

DISTRIBUTION SYSTEM OVERVIEW

Distribution feeder circuits for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder circuit causes a customer outage, which is an allowed outcome for a distribution system. Feeders are designed to facilitate restoration of mainline capacity and restoration of service to most customers with simple manual field switching with some exceptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour.

Distribution Substations

Xcel Energy plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. The maximum ultimate design capacity established in Xcel Energy planning criteria is three transformers at the same distribution voltage.[1] This maximum size balances substation and feeder circuit costs with customer service considerations including limitations of feeder circuit routes emanating from substations, circuit exposure of long feeder circuits, ease of operation, cost of operation, customer outage restoration, and the electrical losses. Over time, transformers and feeder circuits are incrementally added within the established footprint until the substation is built to ultimate design capacity.

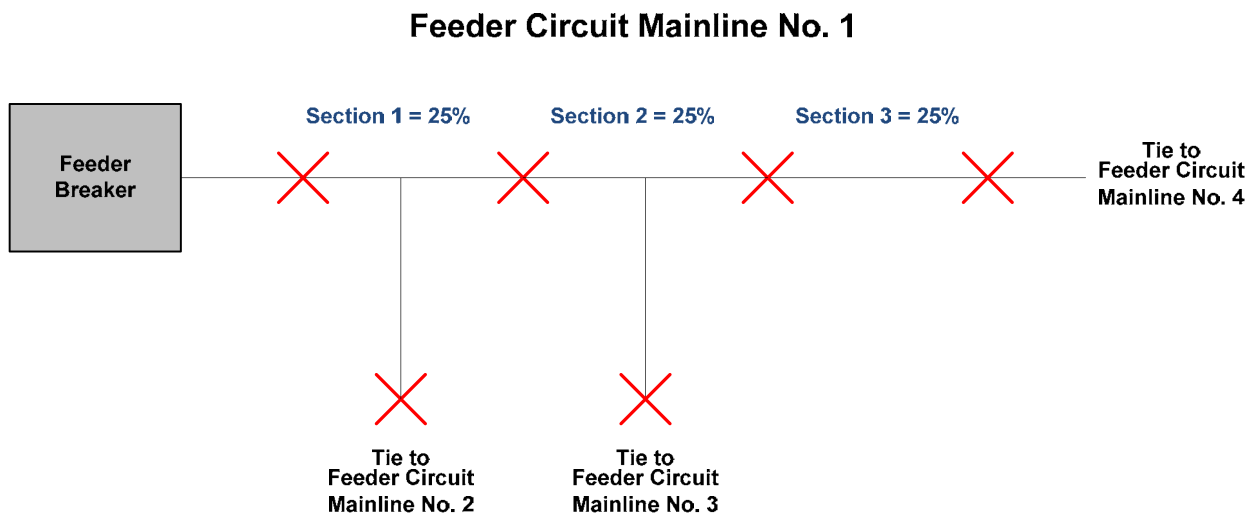
Distribution Feeder Circuits System Intact and First Contingency Planning

Normal operation (also called system intact or N-0 operation) is the condition under which all electric infrastructure equipment is fully functional. First contingency operation (also called N-1 or contingency operation) is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. Each distribution main feeder is generally composed of three equal sections. A feeder circuit should be loaded to no more than 75% of capacity during N-0 conditions. For example, a 12 MVA feeder circuit is designed to be loaded to 9 MVA during normal operating conditions. To achieve this goal, a main feeder is generally designed so that each section is loaded to approximately 25% of the total capacity for the main feeder. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

The figure below depicts a main feeder circuit, including the breaker and the three sections. The Xs in the diagram represent switches that can be activated to isolate or connect sections of a feeder lines.

[1] There is one exception to this criteria. In downtown Minneapolis, the Fifth Street Substation houses four transformers to serve the significant load.

Typical Distribution Feeder Circuit Mainline with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations



DISTRIBUTION SYSTEM DESIGN AND OPERATION

Distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact and first contingency conditions. A distribution delivery system that has adequate N-1 capacity is one in which all customer load can be restored through distribution system reconfiguration by means of electrical switching in the event of the outage of any single element.

Adequate N-1 substation transformer capacity, no feeder normal (N-0) overloads, and adequate field tie capability for feeder first contingency (N-1) distribution restoration are key design and operation objectives. To achieve these objectives, Xcel Energy uses distribution planning criteria to achieve uniform development of Xcel Energy's distribution systems. Distribution Planning considers these criteria when identifying deficiencies with existing distribution systems and identifying improvements to address the identified deficiencies.

Planning Criteria, Distribution Feeder Circuits

While the distribution guidelines vary depending on the specific distribution system, there are several basic design guidelines that apply to all areas of Xcel Energy's distribution system. They are as follows:

- Voltage at the customer meter will be maintained within 5% of nominal voltage, which is typically 120 volts.

- Voltage imbalance goals on the feeder circuits are less than or equal to 3%. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.

- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.

- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75% of capacity. Xcel Energy developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss because adding load to the remaining feeder circuits would cause them to overload. By targeting a 75% loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A typical feeder circuit capable of delivering 12 MVA, for example, is normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

Limitations to Installing Feeder Circuits

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables.

When new feeder circuits are added to a mature distribution system, minimum spacing between feeder circuit main line cables sometimes cannot be achieved because of right-of-way limitations or a high concentration of feeder cables. Adding express feeders to serve distant high-load concentrations requires cable installation across distribution service areas where they do not serve any customer load. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks". When feeder circuits are concentrated in duct banks, those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use thermal modelingsoftware for determining maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks.

When underground feeders fill existing duct lines to the rated thermal capacity, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted.

Planning Criteria, Distribution Substation Transformers

Transformers have nameplate ratings that identify capacity limits. Xcel Energy's Transformer Loading Guide provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The Transformer Loading Guide is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers ("ANSI/IEEE") standard for transformer loading, ANSI/IEEE C57.92.

The Xcel Energy Transformer Loading Guide consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures. The top-oil and hottest-spot temperatures in the Xcel Energy Transformer Loading Guide are the criteria used by Substation Field engineers to determine Normal and Single-Cycle transformer loading limits that System Planning Engineers use for transformer loading analysis. When internal transformer temperatures exceed pre-determined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life". Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer operation generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

To ensure maximum life and the ability to reliably serve customers, Xcel Energy's loading objective for transformers is 75% of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75% are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization, the higher the risk that service will be interrupted in the event of a transformer outage.

Ongoing Distribution System Reliability Assessment

Distribution Planning regularly evaluates loads to determine overloads. Mitigations (projects) are developed to address the overloads. In general, the addition of infrastructure to address overloaded distribution system elements is an ongoing process.

Distribution Planning annually compares feeder circuit historical and forecast peak load demands to distribution feeder circuit maximum loading limits to identify feeder circuits overloaded under system intact (N-0) conditions and feeder circuits overloaded under single contingency (N-1) conditions during peak loading.

Distribution System Planning also annually compares substation transformer historical and forecasted peak load demands on substation transformers to capacity load limits under system intact (N-0) and single contingency (N-1) conditions. Distribution System Planning provides distribution substation transformer loads to the Transmission Planning Department ("Transmission Planning"). Distribution and transmission planners routinely coordinate to identify distribution load impacts to the transmission system.

Distribution Planning then quantifies the amount of overload and the duration of peak loading for feeder circuit and substation transformer overloads under system intact (N-0) and single contingency (N-1 conditions), determines the approximate cost of mitigating the overloads, and identifies the most critical distribution system needs.

When Distribution Planning determines that a distribution system requires additional capacity from a new distribution source, it makes a formal request to Transmission Planning to interconnect to the transmission system. Transmission Planning takes the request and Distribution Planning and Transmission Planning coordinate to develop several options that will address the distribution system deficiencies. Transmission Planning performs analyses to determine the impact of the selected options on the transmission system.

System Planning & Strategic Technology North
Updated 2012

PURPOSE

This document, effective February 4th, 2013 provides the criteria to be used by the transmission planners when studying the performance of Northern States Power Company - Minnesota and Northern States Power Company - Wisconsin (jointly referred to as NSP) transmission facilities. This includes voltage, line loading, transient stability, flicker and transmission line reclosing criteria. The document also provides guidance for acceptable forms of mitigation plans and NSP's policy for use of special protection systems.

APPLICABILITY AND RESPONSIBILITIES

Northern States Power Company – Minnesota and Northern States Power Company – Wisconsin

APPROVERS

Name	Title
Srinivas Vemuri	Senior Engineer, Transmission Planning
Mark J. Wehlage	Manager, NSP Transmission Planning
Ian R. Benson	Director, Transmission Planning & Business Relations

VERSION HISTORY

Effective Date	Version Number	Supercedes	Change
February 4, 2013	1.0	N/A	Initial ProjectWise Document. Original document version is 1.0—ProjectWise version

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1. VOLTAGE CRITERIA

When performing steady state analysis, the following voltage criteria applies to NSP's buses under system intact (pre contingent) and post contingent conditions:

Table 1

Facility	Maximum voltage (p.u.) Pre Contingent	Minimum voltage (p.u.) Pre Contingent	Maximum voltage (p.u.) Post Contingent	Minimum voltage (p.u.) Post Contingent
Default for all buses > 100 kV	1.05	0.95	1.05	0.92
Default for all buses < 100 kV*	1.05	0.95	1.05	0.92
Default for all generator buses**	1.05	0.95	1.05	0.95

*For 34.5 kV load serving buses, pre and post contingent voltage of above 0.9PU would be acceptable.
**For all Category A, B and C contingencies, except Category C3. After a Category C3 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

Table 1 above presents the general voltage criteria for most of the NSP owned facilities; however specific voltage criteria exist for some of the high voltage buses, these criteria are listed below in Table 2

Table 2

Facility	Maximum (p.u.) Pre Contingent	Minimum (p.u.) Pre Contingent	Maximum (p.u.) Post Contingent	Minimum (p.u.) Post Contingent
Roseau 500 kV bus	1.14	0.95	1.14	0.92
Prairie 115 kV main bus	1.09	0.95	1.09	0.90
Prairie 115 kV capacitor bus	1.15	0.95	1.15	0.92
Sheyenne 115 kV capacitor bus	1.15	0.95	1.15	0.92
Running 230 kV capacitor bus	1.10	0.95	1.10	0.92
Roseau 230 kV capacitor bus	1.05	0.95	1.10	0.92

In order to comply with the NUC-001 standard, for nuclear plant off-site source requirements, specific voltage criteria has to be met for Prairie Island and Monticello substation buses. Table 3[1] below provides the list of offsite sources available to the plants, along with the minimum voltage requirement for each of the sources. While planning the

[1] Please refer to the Nuclear Plant Interface Requirements for up to date requirements for the individual plants.

transmission system, it should be ensured that at least two of the sources meet the minimum voltage requirement listed in Table 3 below.

Table 3

Substation	Off site sources	Vmin
Prairie Island	Two sources from the 345 kV bus One sources from 161 kV bus One source from the 13.8 kV bus	98.8% 99.5% -
Monticello	Two sources from the 345 kV bus One sources from 115 kV bus One source from the 13.8 kV bus	99.1% 100.8% -

2. LINE LOADING CRITERIA

The ratings for facilities (transmission lines, transformers and series compensators) owned by NSP are specified in the NSP Ratings Database. The winter and summer ratings of facilities account for the thermal limit of all equipment, and relay loadability limits, as specified in NERC FAC-008 and FAC-009 standards.

When planning NSP's system, for system intact condition, the current flowing through a facility should not exceed the normal rating of that facility. When studying contingency conditions, the current flowing through a facility should not exceed the emergency rating of that facility. During transmission outages, it should be assumed that the system operators would take remedial action when the current on a facility is lower than the emergency rating and greater than the normal rating. When such remedial action is not available, the normal rating of the facility should be used.

Certain facilities on NSP's system are dynamically rated, the ratings of these facilities change based on the ambient conditions, such as wind speed. When monitoring these facilities for overloads, appropriate ratings have to be chosen. The up-to-date list of dynamically rated transmission lines can be obtained from NSP's transmission planning or transmission operations.

3. VOLTAGE DEVIATION CRITERIA FOR SHUNT DEVICE SWITCHING

When performing planning studies for the transmission system, the following criteria applies to the NSP's system:

- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor or inductor), under system intact condition, should not exceed more than 3% at any load serving bus. [based on IEEE 1453.1 and IEC 61000-3-7:2008 standards]
- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor, or inductor), during prior outage of the largest fault current contributing element, should not exceed more than 5% at any load serving bus.

4. VOLTAGE STABILITY CRITERIA

Voltage stability analysis is performed as part of load serving studies, as well as generation outlet studies, to identify the maximum transfer capability of the transmission system before a voltage collapse occurs. While performing this analysis, sufficient voltage margin has to be maintained by operating at or below Pcrit. Pcrit is determined by developing PV (Power-voltage) curves for those buses that have the largest contribution to voltage instability for any give outage. P_{limit} is calculated as the lesser of

- (0.9) * P_{crit} [where P_{crit} is defined as the maximum power transfer or system demand (nose of PV curve)] or
- the maximum power transfer or system demand which does not result in a post-contingent voltage violation as defined in Tables 1 and 2.

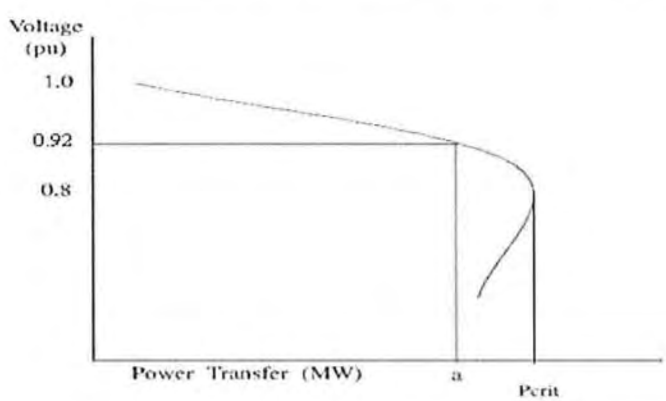

Figure 4.1

5. STEADY STATE PLANNING CONTINGENCIES EVALUATED

The contingencies used for planning studies are based on the currently effective NERC TPL standards. Refer to Table 1 of TPL-001, TPL-002, TPL-003 or TPL-004 standards for the contingencies evaluated for the Bulk Electric System.

Single contingency outages are studied for facilities that are not considered part of the Bulk Electric System.

6. TRANSIENT VOLTAGE CRITERIA

When performing transient stability studies, after the fault is cleared, the following criteria apply to transient voltage on NSP's buses.

Table 4

Facility	Vmax P.U	Vmin P.U
Default for all Buses	1.2	0.7
Fast Switched Capacitor buses	1.65 P.U for <5 cycles	0.7

7. DAMPING CRITERIA FOR TRANSIENT STABILITY STUDIES

When performing transient stability studies, the following criteria apply to generator angle oscillations:

- The generator angles should always be positively damped
- The successive peak ratio (SPPR), defined by
  SPPR=Successive swing amplitude / Previous swing amplitude
  should be less than 0.95
- The damping factor defined by
  %Damping factor = (1-SPPR)*100
  should be at least 5%

The PSS/E model "DAMPCK" performs the calculation of damping based on successive positive peak ratios. For cases where "DAMPCK" fails, Prony analysis could be used to identify the modes. The damping factors of the modes could be calculated using the following expression

$$\text{Damping ratio } \zeta = -\sigma / \sqrt{(\sigma^2+\omega^2)}$$

Where $\sigma \pm j\omega$ represents the mode and the frequency of the mode is given by $\omega/2\pi$.

The damping ratio, for disturbances with faults, should be at least 0.0081633. The damping ratio, for disturbances without faults, should be at least 016766.

8. DISTANCE RELAYING - APPARENT IMPEDANCE CRITERIA

The transient apparent impedance swings on all lines can be monitored by the PSS/E model "MRELY1" against a three zone mho circle characteristics described below:

Circle A = 1.00 x line impedance
Circle B = 1.25 x line impedance
Circle C = 1.50 x line impedance

Apparent impedance transient swings into Circles A or B are considered unacceptable. Any violation of this criterion has to be investigated to ensure that additional transmission elements do not trip after the fault is cleared. Any valid violation has to be appropriately mitigated.

In addition to the generic distance relay model, specific models are included for the out of step relays on the tie lines between US and Manitoba Hydro system. When performing planning studies, it should be ensured that relay margins for the out of step relays are respected as required by the respective transmission owner. Any unintended tripping of the out of step relays is not acceptable. Any valid violation of these criteria has to be communicated with the transmission owner and should be mitigated if required.

9. TYPES OF DISTURBANCES STUDIED

The disturbances simulated for the planning studies are based on the currently effective NERC TPL standards. Refer to the currently effective NERC TPL standards for the contingencies evaluated.

10. SYNC CHECK RELAY - ANGLE SEPARATION CRITERIA

When reclosing a transmission line, sync check relays are used to ensure that the angle separation between the two ends of the line is not too large. This is to ensure generators, close to either end of the transmission line, do not sustain damage due to large change in power. NSP allows a maximum angle separation of 30 degrees for reclosing of a transmission line.

Under certain conditions, lines could be allowed to reclose at angle separation greater than 30 degrees. In order to allow reclosing lines, with angle separation greater than 30 degrees, switching studies have to be performed to demonstrate that the change in power at any generator does not exceed 50% of its rated power [base d on IEEE C50.13-2005].

11. SHORT CIRCUIT CRITERIA

When planning the transmission system, the fault current design capabilities of the facilities should be respected. This includes

- Fault interrupting device capabilities
- Ground grid burn off, and Step and Touch potentials
- Structural strength of bus spans, insulators, etc.
- Personal Protection Equipment for maintenance

Any violation of facilities' capability or personal safety has to be mitigated appropriately.

12. TRANSMISSION PLANS

Any valid violation of criteria, listed in sections 1 through 11, identified through planning study or assessment has to be addressed by developing an appropriate transmission plan.

The plans could involve building new transmission facilities or upgrading existing transmission facilities or re-configuring existing transmission system without causing any new violations.

In addition, use of under-voltage load shedding could be an acceptable short term plan for low voltage violations. Similarly, over current relays could be used as a short term plan for thermal overloads on transmission facilities, provided it does not result in deterioration of transmission system performance.

Operating guides are used by system operators to address specific challenges that are encountered during the day to day operation of the transmission system and to meet the NERC TOP standards. For long term planning purpose, use of operating guides to meet the NERC TPL standards should be limited to address violations associated with prior outage conditions or to address violations associated with category C3 contingencies.

13. OTHER STUDIES

Additional technical studies should be performed as required to maintain system reliability and to follow good utility practice. These include studies related to voltage imbalance, harmonics, sub-synchronous resonance, small signal stability, etc.

14. NSP'S POLICY FOR USE OF SPECIAL PROTECTION SYSTEMS

It is NSPM and NSPW (jointly NSP) policy not to install, own or administer new Special Protection System (SPS), or to expand any existing SPS, to mitigate pre- or post-contingent system reliability concerns on the NSP transmission system (NSP System) or the transmission system of an interconnected neighboring utility transmission system. Reliability concerns include, but are not limited to thermal overloads, voltage violations, and system stability violations.

14.1 RETIREMENT OF EXISTING SPSS OWNED BY NSP

For each SPS already placed in service on the NSP System, periodic reviews will be performed to ensure that the SPS is deactivated by NSP when the conditions requiring its use no longer exist, or system improvements necessary to remove the SPS are in service.

14.2 MODIFICATION OF EXISTING SPSS OWNED BY NSP

Modification of existing SPSs would be allowed if a new transmission project requires altering the facilities associated with an existing SPS. This type of modification should be backed by a supporting technical study that demonstrates that the system reliability would not be degraded due to the modification. In addition, the required approvals from the regional reliability organization should also be obtained in accordance with NERC PRC-015 standard.

The modification of existing SPSs would not be allowed for generator or load interconnections, transmission service requests or to avoid generation curtailment of existing generation resources.

14.3 NEW TEMPORARY SPS

New temporary SPSs could be allowed on NSP's transmission system only if the following conditions are met:

1. If the SPS is needed as a temporary measure to maintain system reliability during construction of a transmission project, such that the SPS could be retired after the completion of the project.
2. If the SPS is proposed as a short term measure to provide transmission service or allow generator or load interconnection. This would be allowed only if there is a written agreement with NSP, with a committed in-service date for the transmission facilities that would eliminate the need for the SPS.

In order to install the temporary SPS, technical studies have to be performed to demonstrate that the system reliability is not degraded. In addition, approval has to be obtained from the regional reliability organization in accordance with the NERC PRC-015 standard.

Midwest reliability Organization (MRO) reviews the effectiveness of each SPS every 5 years. NSP would not participate in this review of temporary SPS at the end of the fourth year, and will retire the temporary SPS at the end of fourth year. This could result in the generator or load losing its ability to stay interconnected to the transmission system or lose its transmission service, if the transmission facilities required for retiring the SPS are not in-service.

Temporary SPSs would not be installed to avoid generation curtailment of existing or future generators that are designated "Energy Resource".

14.4 SPSS OWNED BY ENTITIES OTHER THAN NSP

NSP would not support or participate in the installation of SPSs by any entity on NSP's system that would require tripping or switching of NSP's transmission facilities or any generating facility interconnected to NSP's transmission system.

For an SPS owned and administered by an entity other than NSP, that does not require tripping of NSP's transmission facilities or generating facilities interconnected to NSP's transmission system, that requires installation of monitoring and communication equipment on the NSP System, NSP will cooperate with installation of such monitoring and communications equipment on the NSP System, provided the following conditions are met:

1) The entity owning and administering the SPS agrees to perform the necessary technical studies required to support the need, and the impact of the SPS on the transmission system, as required by applicable NERC standards for Special Protection Systems, and obtain the necessary approval from the applicable regional entity (e.g., the Midwest Reliability Organization)

2) The entity owning the SPS agrees to be responsible for complying with misoperation reporting requirements as required by the applicable NERC standards for SPSs, and will be responsible for coordinating any corrective actions with the NSP System.

3) The entity identified as the Transmission Operator of the SPS, for the SPS owner, would be solely responsible for monitoring the status of the SPS and notifying affected entities of changes in the status of the SPS, including any degradation or potential failure to operate as expected as required by PRC-001-1 R6 and IRO-005-3a R9.

14.5 SPS POLICY EXCEPTION

The only exception to this policy is the case when a SPS is necessary to mitigate sub-synchronous resonance on series compensated transmission lines owned by NSP.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** May 13, 2009

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

- **R1.1.** Be made annually.
- **R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
- **R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
  - **R1.3.1.** Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
  - **R1.3.2.** Be conducted annually unless changes to system conditions do not warrant such analyses.
  - **R1.3.3.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
  - **R1.3.4.** Have established normal (pre-contingency) operating procedures in place.
  - **R1.3.5.** Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R1 and TPL-001-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title: Transmission System Planning Performance Requirements**

2. **Number: TPL-001-2**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes

Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)

2. **Number:** TPL-001-3

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-3_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-3_R1 and TPL-001-3_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-3_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC
Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame
Annually

1.3. Data Retention
None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised

1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

Standard TPL-001-3 — System Performance Under Normal Conditions

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected
    b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm

Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-4**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. 2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. 3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. 4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. 5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. 6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground. 7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. 8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. 9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. 10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. 11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less. 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction. 13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-0b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: Immediately after approval of applicable regulatory authorities.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

> **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).”
2. “…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).”
3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.”

Category B of Table 1 (single Contingencies) specifies:

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing[e]:

4. Single Pole (dc) Line

Note e specifies:

e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. Title: **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. Number: TPL-002-2b

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-1_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-1_R1 and TPL-002-1_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-1_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation
1b	April 2010	Revised footnote ‘b’ pursuant to FERC	Revised

		Order RM06-16-009.	
1b	February 17, 2011	Approved by the Board of Trustees; revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
1b	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2b	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote ‘b’.	

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Requirement Number and Text of Requirement

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following **Category B of Table 1** (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

> **R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.

Background Information for Interpretation

Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:

1. That the assessment is supported by "study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies)."
2. "…these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s)."
3. "Include the effects of existing and planned protection systems, including any backup or redundant systems."

Category B of Table 1 (single Contingencies) specifies:

Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:

1. Generator
2. Transmission Circuit
3. Transformer

Loss of an Element without a Fault.

Single Pole Block, Normal Clearing[e]:

4. Single Pole (dc) Line

Note e specifies:

e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

The NERC Glossary of Terms defines Normal Clearing as "A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

Conclusion

TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.

This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk

Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp's comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires "a written summary of plans to achieve the required system performance," including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

Standard TPL-003-0a — System Performance Following Loss of Two or More BES Elements

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

Standard TPL-003-0a — System Performance Following Loss of Two or More BES Elements

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 23, 2010

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation
0b	February 7, 2013	Interpretation adopted by NERC Board of Trustees	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	**Contingencies** Initiating Event(s) and Contingency Element(s)	**System Limits or Impacts**		
		System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

Standard TPL-003-0b — System Performance Following Loss of Two or More BES Elements

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee	
Date submitted:	December 12, 2011
The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).	
Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.
Please explain the clarification needed (as submitted).	
This interpretation request has been developed to address Commission concerns related to the term "Single Point of Failure" and how it relates to system performance and contingency planning	

clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system

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[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Question 1

For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[9] of either "stuck breaker" or "protection system failure" contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

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[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"
[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3ø) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase "(stuck breaker or protection system failure)." Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions "(stuck breaker or protection system failure)" must be considered.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term "Delayed Clearing" that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system's normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full

[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example "…any protection system component such as, relay, circuit breaker, or current transformer..." because the component "circuit breaker" is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of "protection system" inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team's further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, "Protection System," the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-2a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-2_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-2_R1 and TPL-003-2_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-2_R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation

1a	February 17, 2011	Approved by the Board of Trustees; revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
1a	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2a	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote ‘b’.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote ‘b’ is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote ‘b’
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote ‘b’ (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote ‘b’ utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote ‘b’ which must include the following:

1. Conditions under which Firm Demand interruption under footnote ‘b’ would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-2b

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote ‘b’ in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote ‘b’ remains in effect until the revised Footnote ‘b’ becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-2_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-2_R1 and TPL-003-2_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-2_R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

D. Regional Differences

1. None identified.

Version History

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B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

Standard TPL-003-2b — System Performance Following Loss of Two or More BES Elements

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
   a. Date, time, and location for the meeting
   b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
   c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
   a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historical performance
4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote 'b'
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b'
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b'
8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators

<u>III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote 'b' is Required</u>

Before a Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote 'b' if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote 'b', or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote 'b' is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote 'b', the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 'b' for Firm Demand interruption.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, ‘critical system conditions’ in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Appendix 2

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee	
Date submitted:	December 12, 2011
The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).	
Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.
Please explain the clarification needed (as submitted).	
This interpretation request has been developed to address Commission concerns related to the term	

"Single Point of Failure" and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)

[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."

response.

Question 2: For the phrase “Delayed Clearing[5]” used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[9] of either “stuck breaker” or “protection system failure” contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[8] Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”
[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3ø) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase "(stuck breaker or protection system failure)." Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions "(stuck breaker or protection system failure)" must be considered.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term "Delayed Clearing" that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system's normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example "…any protection

[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

A. Introduction

1. Title: System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. Number: TPL-004-0

3. Purpose: System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

5. Effective Date: April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number:** TPL-004-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	February 7, 2013	Interpretation adopted by NERC Board of Trustees	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

Date submitted:	December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to

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[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)
[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."
[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Question 1

For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[9] of either "stuck breaker" or "protection system failure" contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted

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[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"
[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3ø) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase "(stuck breaker or protection system failure)." Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions "(stuck breaker or protection system failure)" must be considered.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term "Delayed Clearing" that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system's normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example "…any protection system component such as, relay, circuit breaker, or current transformer…" because the component "circuit breaker" is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of "protection system" inferred the

[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

NERC glossary term and the components described therein; however, based on the interpretation drafting team's further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, "Protection System," the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number:** TPL-004-2

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-2_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-2_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Approved by the Board of Trustees; revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote ‘b’.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Firm Demand interruption under footnote 'b' is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 'b' is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

   b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)

2. **Number:** TPL-004-2a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability**:

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** The application of revised Footnote 'b' in Table 1 will take effect on the first day of the first calendar quarter, 60 months after approval by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the effective date will be the first day of the first calendar quarter, 60 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. All other requirements remain in effect per previous approvals. The existing Footnote 'b' remains in effect until the revised Footnote 'b' becomes effective.

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five).

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Have all projected firm transfers modeled.

R1.3.5. Include existing and planned facilities.

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

B. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-2_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-2_R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

D. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	February 17, 2011	Approved by the Board of Trustees; revised footnote ‘b’ pursuant to FERC Order RM06-16-009.	Revised (Project 2010-11)
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
2	February 7, 2013	Adopted by NERC Board of Trustees. Revised footnote ‘b’.	
2a	February 7, 2013	Interpretation adopted by NERC Board of Trustees.	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Firm Demand interruption under footnote 'b'
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 'b' (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 'b' utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following:

1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Firm Demand MW to be interrupted with:
    a. The estimated number and type of customers affected

    b. An explanation of the effect of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community
3. Estimated frequency of Firm Demand interruption under footnote ‘b’ based on historical performance
4. Expected duration of Firm Demand interruption under footnote ‘b’ based on historical performance
5. Future plans to alleviate the need for Firm Demand interruption under footnote ‘b’
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’
7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote ‘b’
8. Assessment of potential overlapping uses of footnote ‘b’ including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Interruptions of Firm Demand under Footnote ‘b’ is Required

Before a Firm Demand interruption under footnote ‘b’ is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’ if either:

1. The voltage level of the Contingency is greater than 300 kV
    a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Firm Demand interruptions under footnote ‘b’, or
    b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Firm Demand interruption under footnote ‘b’ is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Firm Demand interruption under footnote ‘b’, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote ‘b’ for Firm Demand interruption.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee	
Date submitted:	December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

Standard	Requirement (and text)
TPL-003-0a	**R1.3.1** Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	**R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	**R1.5.** Consider all contingencies applicable to Category C.
TPL-004-0	**R1.3.1.** Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	**R1.3.7.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	**R1.4.** Consider all contingencies applicable to Category D.

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an Industry Advisory — Protection System Single Point of Failure[1] (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[2] of either "stuck breaker" or "protection system failure" contingency[3], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1[4] requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

Question 2: For the phrase "Delayed Clearing[5]" used in Category C[6] contingencies 6-9 and Category D[7] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[8] require an entity to

[1] NERC Website: (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf)
[2] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[3] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[4] "*Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts*."
[5] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[6] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase "Delayed Clearing" used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term "Delayed Fault Clearing." While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to "stuck breaker" or "protection system failure" contingency assessments.

Question 1

For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects[9] of either "stuck breaker" or "protection system failure" contingency[10], or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I,

[7] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[8] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"
[9] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.
[10] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3ø) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase "(stuck breaker or protection system failure)." Footnote (e) explains that "Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." The parenthetical further emphasizes that the failure may be a "stuck breaker or protection system failure" that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions "(stuck breaker or protection system failure)" must be considered.

Question 2

For the phrase "Delayed Clearing[11]" used in Category C[12] contingencies 6-9 and Category D[13] contingencies 1-4, to what extent does the description in Table 1, footnote (e)[14] require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term "Delayed Clearing" that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system's normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example "…any protection system component such as, relay, circuit breaker, or current transformer..." because the component "circuit breaker" is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of "protection system" inferred the NERC glossary term and the components described therein; however, based on the interpretation

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[11] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.
[12] As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.
[13] As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.
[14] Footnote (e) Delayed Clearing: "failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,"

drafting team's further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, "Protection System," the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.