

# Information Session

WECC intention to adopt new reliability standard for  
Contingency Reserves – BAL-002-WECC-01

February 17<sup>th</sup>, 2009

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Reliable **Power**

Reliable **Markets**

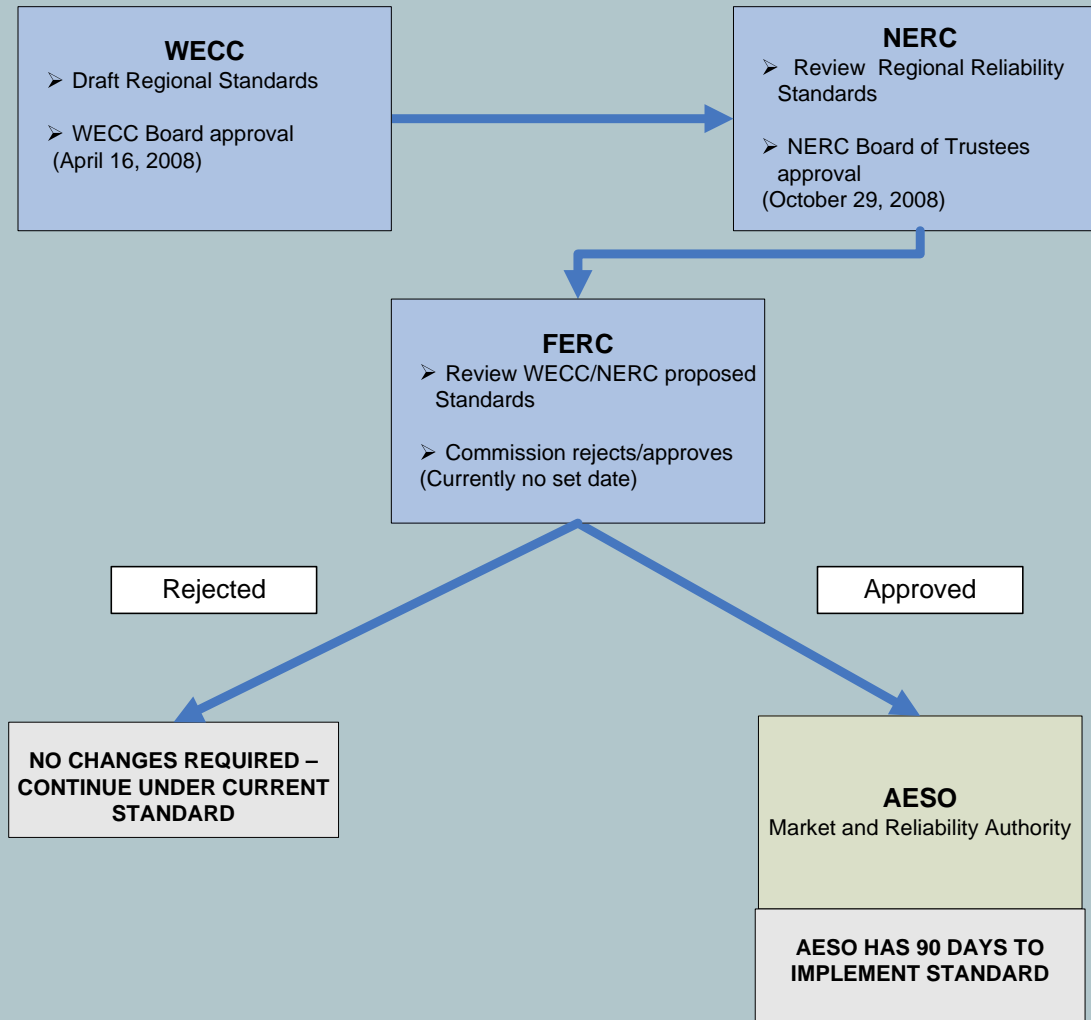
Reliable **People**



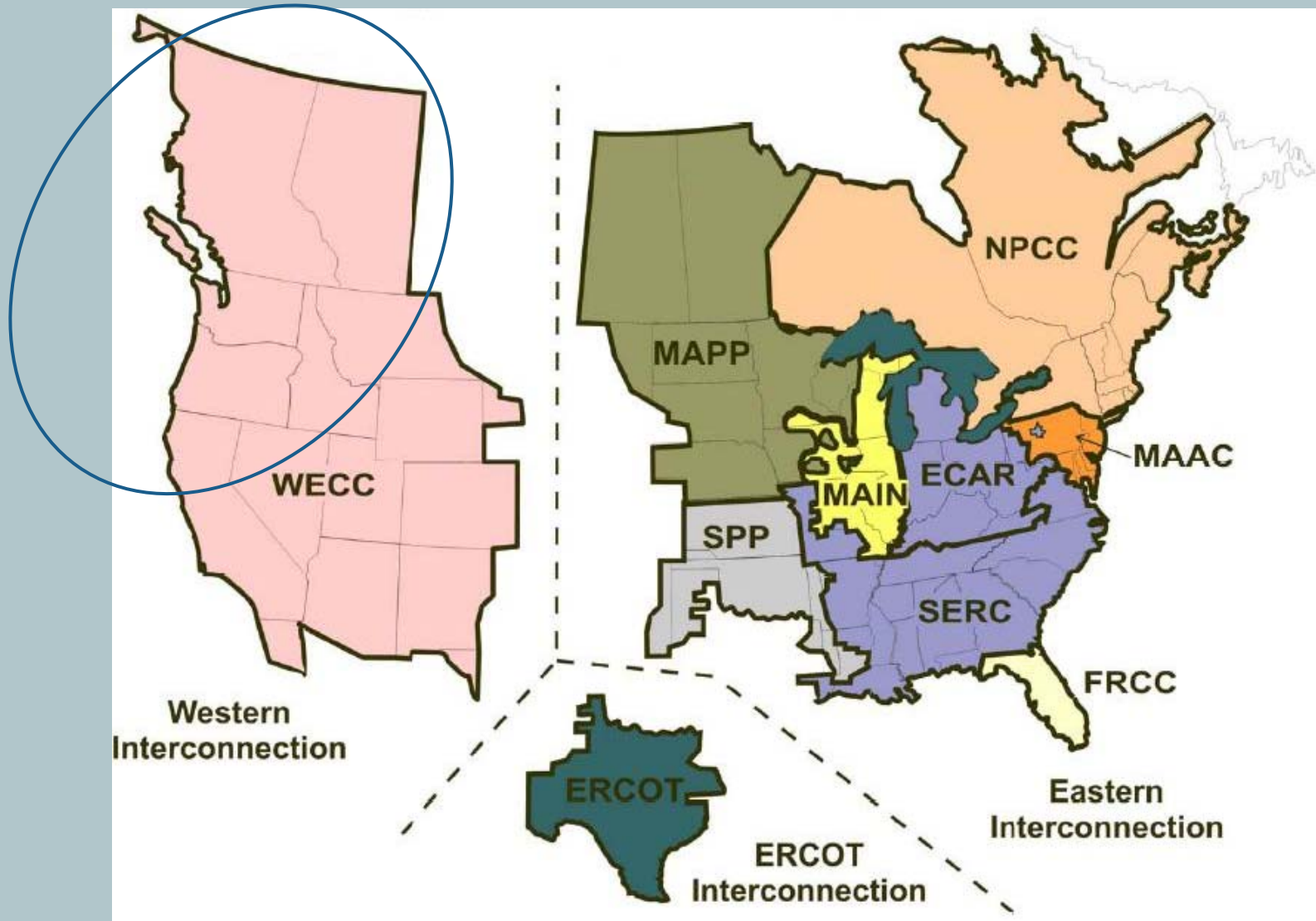
# Agenda

- Introductions
- Background information
- Why the change?
- Key changes
- Calculation methodologies
- Different scenarios
- Question and comment mechanism

# WECC/NERC Reliability Standards



# North American Electric Reliability Corporation



# Commitment to Reliability

- Committed to follow Western Electricity Coordinating Council (WECC) criteria
- Northwest Power Pool (NWPP) reserve sharing group
- Requirement to carry a minimum amount of contingency reserves
- 5% hydro/wind +7% thermal (“5+7 Rule”) or Single Largest Contingency

# Ancillary Service Products

## OPP 400 Series – Reserve Management

- Operating Reserves = Regulating Reserves + Contingency Reserves
- **Contingency Reserves = Spinning Reserves + Supplemental Reserves**
- Supplemental Reserves = SUPL (load) + SUPG (generation)
- Maximum of 80 MW per generator

# Why the change?

- To distribute the contingency reserve requirements in the Western Interconnection more fairly between all entities
- To clarify ambiguities related to the Contingency Reserve requirements that exist in today's Standard including the definition of load responsibility and the inclusion of import and export transactions
- To change the requirement to be fairer to both load and generation entities

# Key changes

Before	After
<b>Contingency Reserve Obligation</b>	
Contingency Reserves = 5% of FLR served by hydro and wind generation + 7% of FLR served by thermal generation	Contingency Reserve Obligation = 3% load +3% generation
<b>Technical Requirements</b>	
Maintaining required CR levels for up to 60 minutes	Maintaining required CR levels for up to 105 minutes
<b>Load Calculation</b>	
“Firm Load Responsibility” (FLR) based on Demand Transmission Service (DTS) contracted MW	Based on Net Generation + “Net to Grid” MW for self-suppliers
<b>Interties</b>	
Currently CR only carried on exports	Net affect of imports and exports

# Contingency Reserves – Current Requirement

## Current Contingency Reserves Calculation Method

- 5% of **Firm Load Responsibility** served by hydro and wind generation  
+ 7% of **Firm Load Responsibility** served by thermal generation
- “Firm Load Responsibility” means the Alberta **area’s firm load** demand served under **Demand Transmission Service (DTS)**, plus **AIES losses**, plus firm export transactions, minus firm import transactions, minus that **firm load** under the **ISO’s DTS** which is under contract to provide **operating reserves**.
- $FLR = \text{Internal Load} - \text{Net Interchange} - \text{Non-firm Load of Self suppliers (COR)}$

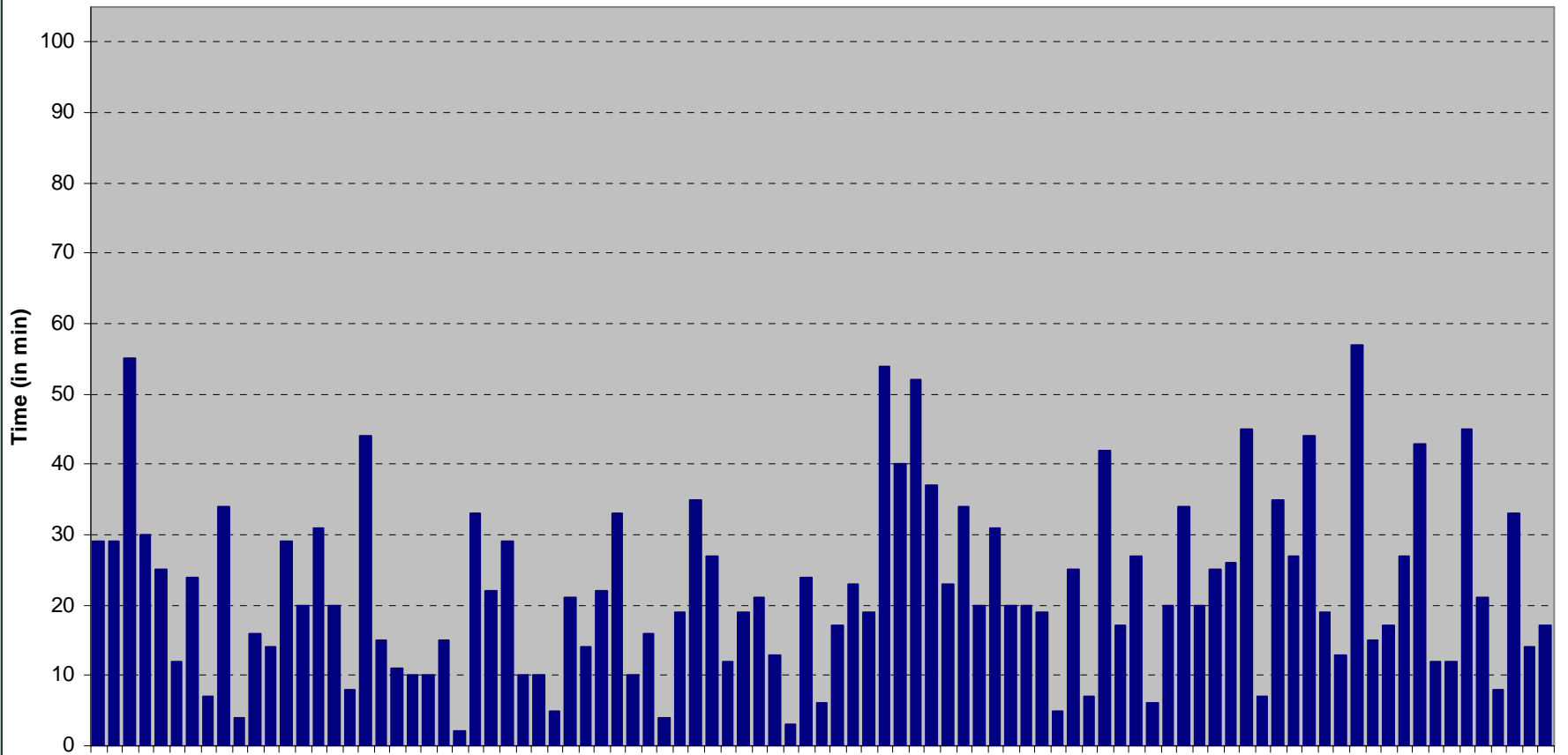
# Contingency Reserves – WECC Proposed

## NEW Contingency Reserves Calculation Method

- $CR = 3\% \text{ load (generation - unit service - Net Actual Interchange) + 3\% \text{ of net generation (generation - unit service)}$
- No longer calculating load demand served under **Demand Transmission Service (DTS)** but measuring at point of interconnection to the Alberta system, including self-supplying industrial systems
- Net generation is the sum of all generation minus unit service in the Alberta area. For self-supplying industrial systems the “net to grid” measurement will be used.

# Historical Directive Length

AS Directive Length (SR, SUPG) by Event



Jan 2008 - Dec 2008

# Different system scenarios

Alberta Internal Load (AIL)	8734	Low load 7000	High load 9000	8734	8734
Old Load “Firm Load Responsibility”	7839	6105	8105	7179	8499
New Load (L+G)	7139	5405	7405	6479	7799
Net Actual Interchange	0	0	0	import -660	export +660
Old CRO	543	421	561	660 (496)	588
New CRO	428	324	444	660 (409)	448

# Process for comments

- Questions - [info@aeso.ca](mailto:info@aeso.ca)
- OPP 402, 403 and 405 Rule changes – comments due February 27, 2009
- Implementation time frame – 90 days after Federal Energy Regulating Commission (FERC) approval