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—Mark Meyer

RMS to mandate transmission system reliability

North America's first mandatory electric grid Reliability Management System will be implemented this summer by the Western Systems Coordinating Council. Western played a major role in developing the RMS, the first contract-based approach to ensuring reliability.

In December 1998, after evaluating a nearly one-year pilot program, WSCC members voted to implement the RMS program this summer. A contract-signing ceremony is set for today in San Francisco.

What this means essentially is that WSCC members, who make up one of 10 regional councils under the North American Electric Reliability Council, will be required to comply with mandatory rules regarding bulk system reliability. Formerly, enforcement was through voluntary "peer pressure" and expectations that utilities would "do the right thing."

Voluntary compliance no longer works

Mark Meyer, a power operations specialist at CSO, said voluntary compliance no longer works well because of utility industry deregulation, which has forced utilities to become much more competitive. "The drive by utilities to reduce costs and look at others in the marketplace as cutthroat competitors rather than friends caused industry observers to believe bulk system reliability could not be maintained unless compliance was mandatory," he said.

Work began on the RMS in early 1997 with the formation of the Mandatory

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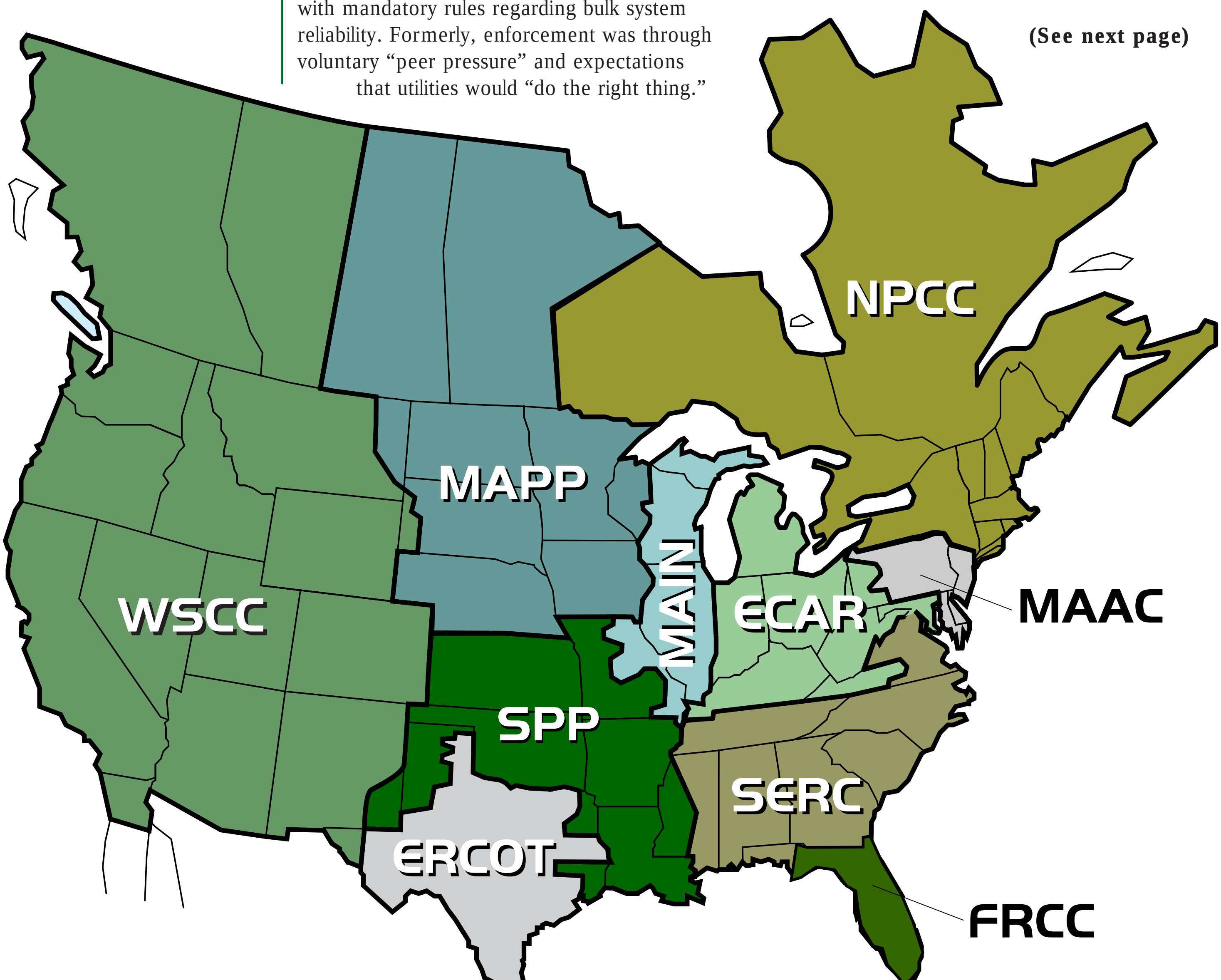

Compliance Implementation Policy Group. **Tyler Carlson,** Desert Southwest regional manager, represents Western on this group. Other Western employees serving on related work groups are **Bob Fullerton,** Incentives and Sanctions Task Force; **Susan Earley,** Legal Task Force; and Meyer, Standards Development Task Force.

Each group played a different role in accomplishing tasks. The Policy Group guided the entire effort, while other groups developed strategies to make the new system function. Developing performance criteria, detailing legal considerations and preparing sanctions to punish noncompliance as well as reward good performance were among the groups' many duties and considerations.

"These were all daunting efforts," Meyer said. "To bind your company to a system that may result in embarrassment and monetary sanctions is a big step to take."

How Western is faring

Currently, the new system is under close scrutiny in an ongoing pilot project evaluation period, with no fines or nonmonetary sanctions, Meyer said.

Like most other members, Western is getting mixed results. "For the most part, Western's performance has been good," Meyer said. "However, we violated some criteria. We are taking steps to avoid future violations."

Western will be seriously challenged to avoid sanctions when the system is officially implemented this summer, Meyer continued. He pointed out that Rocky Mountain Region, for instance, could at critical times have difficulties maintaining flows below operating transfer capability levels on two troublesome transmission paths—TOT3 from southeastern Wyoming to Colorado and TOT2A from southwestern Colorado to New Mexico.

Both these paths have multiple owners and are heavily affected by loop flow (power flowing on a transmission path other than the path for which it was intended). This makes it particularly difficult for Western's operators to keep actual flows below the transfer limits during critical periods, although they can try to do this by cutting energy schedules, rearranging generation and using phase-shifting transformers.

NERC is now developing a "mandatory compliance" process that will include both operating and planning/engineering standards. Phase I of a four-phase program is already under way. Ultimately, utilities will also have to comply with nationwide rules for system reliability.

How RMS works

Western Systems Coordinating Council has chosen to take a "contractual" approach to mandatory compliance. Most members, including Western, voted to sign binding contracts to abide by the agreement last December. A signing ceremony is set for today in San Francisco.

The RMS agreement:

- deals only with operating—not planning and engineering—criteria.
- will be implemented in three phases; each includes a one-year evaluation period to allow for modifications.
- establishes for each criteria a full compliance level plus four levels of noncompliance.
- provides nonmonetary and monetary sanctions based on both severity and number of noncompliant events in a given reporting period.

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Three-phase implementation

RMS will be implemented in three phases. The Phase I pilot program began in February 1998 and is ongoing. The Phase II evaluation period, which added four more criteria, began in September 1998 and will be implemented about six months after Phase I officially begins this month. Phase III criteria should be finalized late this summer and will follow Phase II after about six months.

Phase I criteria are:

- **NERC Control Performance Standard 1 and Control Performance Standard 2:** CPS1 and CPS2 are measures of how well a control area matches generation to load. This is what keeps the frequency at the desired 60 hertz.
- **NERC Disturbance Control Standard and Operating Reserves:** DCS measures a control area's ability to recover from a disturbance (loss of generation or load). Operating reserves (unloaded on-line generation) are required to adequately respond to a disturbance.
- **Automatic Voltage Regulators and Power System Stabilizers:** This criteria requires that generators have their automatic voltage regulators and power system stabilizers inservice when on-line.
- **Operating Transfer Capability:** This criteria requires transmission path operators maintain the scheduled flow and actual flow on the path at or below the OTC.
- **Interchange Schedule Tagging:** This criteria requires that all energy schedules be properly tagged using NERC/WSCC approved methods. This is an evolving area in power system operation and the pilot program encountered many problems. Interchange Schedule Tagging has been deferred to Phase II.

Phase II criteria are:

- **Operating Transfer Capability Calculation:** This criteria requires that transmission path operating transfer capabilities be calculated according to WSCC-approved methods, be available to system operators and be coordinated among affected parties. This criteria only applies to 38 major paths in the WSCC.
- **Relays and Remedial Action Schemes:** This criteria requires that transmission path operators certify annually that the protective relay schemes and/or remedial action schemes are appropriate; that the relay/RAS settings and logic are correct and the information is available to system operators; and that these systems are coordinated with affected parties. The criteria for the protective relay systems applies to 38 major paths in the WSCC and the RAS criteria applies to 8 major RAS systems in the WSCC.
- **Misoperation of Relay/RAS Systems:** This criteria requires that relays/RAS that have misoperated must be removed from service (or the path removed from service or derated) within eight hours of recognizing the misoperation. The relay portion applies to 38 major paths in the WSCC and the RAS portion to 8 major RAS schemes in the WSCC.
- **Interchange Schedule Tagging:** Tagging has been moved to Phase II because of problems encountered in Phase I and the changing landscape of interchange tagging.

Phase III criteria are expected to be finalized later this summer. Potential criteria are transmission line availability, transmission line disturbance performance, transmission facility maintenance, system operator training and Unscheduled Flow Mitigation Plan compliance.