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Dean J. Miller *ISB #1968*
McDEVITT & MILLER LLP
420 West Bannock Street
P.O. Box 2564-83701
Boise, ID 83702
Tel: 208.343.7500
Fax: 208.336.6912
joe@mcdevitt-miller.com

Attorneys Cassia Wind Gulch Park LLC and Cassia Wind LLC

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IDAHO PUBLIC UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

CASSIA GULCH WIND PARK LLC AND CASSIA WIND FARM LLC Complainants v. IDAHO POWER COMPANY Respondent	**Case No.** IPC-E-06-21 **MEMORANDUM IN SUPPORT OF COMPLAINT**

Statement of the Case

As part of its integrated backbone electric transmission system, Idaho Power Company ("Idaho Power") owns and operates a 138 kV transmission system in the Twin Falls, Idaho, area. Idaho Power has received requests for the integration of up to 200 MW of new generation to be connected to the 138 kV system.[1] Cassia Gulch Wind Park LLC and Cassia Wind Farm LLC (collectively referred to herein as "Cassia" or the "Projects") are among those requesting interconnection. They are "small power production" Qualifying Facilities ("QFs") within the meaning of the Public Utility Policy Regulatory Act ("PURPA"), will generate renewable power from wind, and will sell their entire output to Idaho Power.

[1] Whether the full 200 MW of possible new generation will actually be constructed is unknown.

Under normal operating conditions ("N-0") the existing Idaho Power transmission has capacity sufficient to absorb the potential new generation in the Twin Falls area of Idaho. It, however, is common utility practice to model or evaluate the operation of a backbone transmission assuming that one line of the system is out of service ("N-1 contingency"). Idaho Power believes that under N-1 contingency conditions the addition of 200 MW of generation at the Twin Falls 138 kV system could create thermal overloads within its integrated system. To prevent the possible occurrence of thermal overloads under N-1 contingency conditions, Idaho Power proposes to construct a series of transmission system upgrades in four phases.[2] The estimated total cost of the transmission system upgrades is approximately sixty million dollars ($60 million).

With the exception of a relatively small portion of these system upgrade costs to be born by Idaho Power, Idaho Power claims and asserts that the $60 million cost of its transmission system upgrades should be borne, in the first instance, by the Qualifying Facilities proposing to connect their wind farms to the Idaho Power transmission system. This is in addition to the several million dollars in interconnection costs normally borne by a QF to interconnect a new wind farm to a 138 kV utility system, such as the radial connection line and step-up transformer equipment.

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[2] The engineering and planning assumptions underlying Idaho Power's claim that system upgrades are necessary are not an issue in this case, which is intended to resolve only the threshold question of whether the cost of transmission upgrades should be assigned to Qualifying Facilities. Cassia, however, does not concede that Idaho Power's engineering and planning assumptions are correct. For example, the thermal overload claimed by Idaho Power occurs at the rated load of the integrated system. Cassia is informed that this is a very conservative planning assumption and that a more common industry practice is to determine overload at an elevated level of between 110% and 115% of rated load. Under that assumption there would be no thermal overload in an N-1 contingency case and none of the proposed improvement would be necessary. This is one of the reasons Cassia suggests that the cost of upgrades be borne by Idaho Power and thus subject to prudence review in a general rate proceeding. *See* Memorandum in Support of Complaint, pg. 13.

As established by the Affidavit of Jared Grover, filed with the Complaint, the magnitude of these additional transmission system upgrade costs is such that, if assigned to Cassia, the economic viability of the Projects would be seriously compromised, if not destroyed all together. This not only would adversely affect Cassia, it would also adversely affect the utility ratepayers and citizens of the State of Idaho, for the reasons given below.

Argument and Authorities

The Idaho Public Utilities Commission has jurisdiction to define the interconnection costs for which Qualifying Facilities are responsible.

The regulations of the Federal Energy Regulatory Commission ("FERC") make clear that state commissions such as the Idaho Public Utilities Commission (the "Commission") have a range of authority in which to determine the interconnection costs that are the responsibility of the qualifying facilities. The FERC, in 18 C.F.R. § 292.306, provides:

> (a) Obligation to pay. Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.
>
> (b) Reimbursement of interconnection costs. Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

Interconnection costs are further defined by the FERC in 18 C.F.R. § 292.101(b)(7):

> Interconnection costs means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

As part of its efforts to implement the open access policies of Order No. 888, the FERC in two major orders, Order No. 2003 *Standardization of Generator Interconnection Agreements*, and again in Order No. 2006, *Standardization of Small Generator Interconnection Agreements and Procedures*, made it clear that state commissions retain authority to determine and allocate interconnection costs: "When an electric utility is required to interconnect under section 292.303 of the Commission's regulations, that is, when it purchases the QF's total output, the state has authority over the interconnection and the allocation of interconnection costs." Order No. 2006, pg. 135, para. 516. In other words, the FERC has jurisdiction over the interconnection cost issue only if the QF is going to receive transmission service over the host utility's system, rather than selling all of its power to the host utility at the point of interconnection. This Commission has recognized its authority to interpret and implement these PURPA regulations on interconnection of QFs. *See Arkoosh v. Idaho Power Co.*, Case No. U-1006-237, Order No. 19442 (1985).

Idaho Power's Schedule 72 does not specify responsibility for transmission grid upgrades.

To implement the interconnection obligations of 18 C.F.R. § 292.306, this Commission has approved Idaho Power's Schedule 72—Interconnections to Non-Utility Generation. *See In the Matter of the Application Idaho Power Company to Amend Schedule No. 72*, Case No. IPC-E-01-38, Order No. 29092; *In the Matter of the Application of Idaho Power Company for Approval of an Interconnection Tariff*, Case No. IPC-E-90-20, Order No. 23631.

It is clear, however, that Schedule 72 addresses interconnection costs between the QF's generating facility and the point of interconnection with the utility's existing distribution or transmission system. It does not address responsibility for upgrades to the transmission grid that are beyond (or "down-stream") of the point of physical interconnection between the QF connection line and the utility's existing equipment. In other words, Schedule 72 is focused on the cost responsibility for the "driveway" for independent generation, rather than on the "highway" for all power flowing through the system. In neither Case No. IPC-E-90-20 nor case No. IPC-E-01-38, were such "down-stream" or "highway" upgrades discussed or considered. Schedule 72 does not answer the question as to who is responsible for the type of transmission grade upgrades that Idaho Power is proposing for the Twin Falls area.

Indeed, it appears from statements by Idaho Power, made in its proposal for the assignment of cost responsibility for its transmission system upgrades to Cassia, that Idaho Power is proposing to treat Cassia as a "network resource" under its Open Access Transmission Tariff ("OATT") pursuant to the FERC's current open access policies implementing Order No. 888, rather than as a QF that will be selling its entire output to Idaho Power and interconnecting under Schedule 72.

Specifically, Idaho Power proposes to treat QF payments for grid upgrades as contributions or advances in aid of construction and to refund them to the QFs over a period of time.[3] In Order Nos. 2003 and 2006, relating to standardization of generator interconnection, the FERC adopted a policy requiring the generator to initially fund the cost of network upgrades with reimbursement subsequently over time. Idaho Power follows and implements these procedures for its OATT services through its web-based Open Access Same Time Information System (OASIS), which may be viewed at: http://www.idahopower.com/aboutus/business/generationInterconnect/. Again, however, the

[3] The details of Idaho Power's refunding proposal were explained by Idaho Power at a meeting of interested parties on August 15, 2006 in Boise. Participation in that meeting, however was conditioned upon execution of a confidentiality agreement, which Cassia executed. Accordingly, the details of the refunding proposal are not set out here. In Cassia's view these details are not relevant to the basic question presented by this Complaint, which is, who, as between the utility and the QF, should bear initial responsibility for the cost of transmission system upgrades. Further, in presenting the factual recitals in this Complaint, Memorandum and Affidavit, Cassia has carefully attempted to comply with the confidentiality obligations imposed by the agreement it executed.

FERC made clear in those orders that its policies with respect to generators connecting to a transmission system in the open access environment were not applicable to QFs, such as Cassia, that sell their entire output to the utility to which the QF is interconnecting.

In other words, Idaho Power by its actions appears to recognize that Schedule 72 does not address responsibility for "down-stream" or "highway" upgrades, and is instead seeking to force-fit Cassia into a cost responsibility regime that, as reflected in FERC's Order Nos. 2003 and 2006, does not apply to a QF selling its entire output to the host utility.

The Commission should require that the cost of grid-related upgrades be rolled into Idaho Power's transmission rates, not directly assigned to Cassia and other QFs.

Cassia respectfully urges the Commission to adopt a policy requiring "rolled-in treatment" of transmission system grid-related upgrades for the following reasons:

A. Requiring "new" generators to bear the cost of grid upgrades discriminates in favor of "old" generators.

Directly assigning the cost of grid upgrades to new generators necessarily implies that existing generators—usually generation owned by the transmitting utility—have an entitlement to the system as it exists and have no cost responsibility when upgrades are required. It postulates that a new power source is responsible for the entire expense of system upgrades, even though existing sources may constitute the great majority of the load.

The Idaho Supreme Court has specifically condemned this form of discrimination between old and new connectors. In *Building Contractors v. Idaho Public Utilities Commission,* 128 Idaho 534, 916 P.2d 1259 (1996), the Commission directly assigned costs of certain system upgrades to customers connecting to the system after a certain date. On appeal, the Supreme Court reversed, holding that "old" customers were just as much responsible for the need for additional investment as were "new" customers, and that assigning all costs to the "new" discriminated against the "old" customers. "Each new customer that has come onto the system *at any time* has contributed to the need for new facilities. No particular group of customers should bear the burden of additional expense…." 128 Idaho at 539 (emphasis added).

The same obviously holds true here. Allowing "old" generators—most likely Idaho Power—to avoid cost responsibility for grid upgrades discriminates against "new" generators who are not utility-owned resources.

B. <u>Requiring QFs to pay for Idaho Power's network upgrades discriminates against less costly means of ensuring reliability.</u>

There appear to be less costly alternatives to the grid upgrade investments proposed by Idaho Power. As Cassia understands it, N-1 Contingencies—i.e. the loss of a transmission segment in the integrated transmission system—are expected to occur during only a few hours of each year. During those hours of N-1Contingency, there is the *potential* of thermal overload on lines remaining in service, apparently. Cassia is informed that an industry-recognized engineering alternative to the construction of new facilities to meet N-1 contingency congestion is the implementation of protocols known as Special Projection Schemes ("SPS") or Remedial Action Schemes ("RAS").

Under SPS or RAS protocols, pre-determined amounts of generation from identified generators are curtailed during an N-1 outage, allowing the transmission system to ride-through the outage without causing thermal overload to the system.

RAS protocols are accepted techniques among prudent transmission design professionals. *See* attached excerpts from *Western Electricity Coordinating Council,* Remedial Action Scheme Design Guide (May 18, 2006), wherein it is stated:

> "Remedial action schemes are applied to solve *single* and credible multiple- contingency problems. These schemes have become more common primarily because they are less

> costly and quicker to permit and build than other alternatives such as constructing major transmission lines and power Plants." (WECC Design Guide, pg 1, emphasis added).

The Projects have signed Firm Energy Sales Agreements with Idaho Power, which agreements have been approved by the Commission. *See* Case No. IPC-E-06-10, Order No. 30086; Case No. IPC-E-06-11, Order No. 30086. These agreements contain several provisions allowing the curtailment by Idaho Power of the Cassia generation when necessary to protect the integrity of the Idaho Power system (see, e.g., Article XIII, Article XVI, and Appendix B-7 & B-9). An SPS or RAS solution would be fully consistent with an implement of Idaho Power's existing contractual rights to protect its system.

Cassia has offered to participate in an RAS or SPS solution, but Idaho Power has declined, insisting instead on constructing $60 million dollars of facilities, with the cost assigned—at least initially—to Cassia and similarly situated projects. One must wonder if Idaho Power's attitude would be the same if it was unable to off-load the grid upgrade costs to third parties, but was instead required to choose to invest at the expense of its shareholders between making the proposed grid upgrades or implementing a RAS if it were the one developing the new wind generation in the Twin Falls area.

In utility regulation, preventing discrimination takes many forms. One of them is the general principle that, if a utility customer qualifies for service under more than one rate schedule, the utility is required to provide service under the least expensive rate schedule to the customer. By analogy, if an SPS or RAS is a less expensive, but adequate, alternative to enormous system upgrade expenses, then the SPS or RAS should be the system reliability solution that is utilized.

C. Requiring wind generators to pay grid-related upgrade costs discriminates against wind resources.

Renewable resources are particularly different from traditional utility generation. As the Public Utility Commission of Texas, a leader in the encouragement of renewable resource development once observed:

> Renewable resources are distinctly different from coal or natural gas. The wind and solar energy not captured and used today vanishes and can not be recovered. In addition, they are distinctly different in their ability to be transported. Coal and gas can be transported to a suitable location for conversion to electricity, but most renewable resources must be exploited where they are found. . . . . Using these resources will improve the air quality, yet their environmental benefits are wasted unless they are exploited. 25 Tex.Reg. 82, 99 (2000).

As the foregoing indicates, an obvious characteristic of wind projects is that they must be located at the site of the wind resources. Those locations are often, as in this case, located remotely from Idaho Power's electric loads. If grid-related upgrade costs are directly assigned, wind QFs, which have limited flexibility with respect to site selection, are disadvantaged *vis a vis* QF and non-QF generation technologies that have flexibility to locate nearer to the utility's load center. This constitutes yet another form of discrimination created by the Idaho Power proposal.

D. At a minimum, it should be presumed that the net incremental cost of network upgrades is zero.

The FERC-promulgated definition of interconnection costs contains an important limitation. The QF is responsible for interconnection costs only "to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations." 18 C.F.R. § 292.101(b)(7). In *Petition of Missisquoi Associates*, 1985 WL 287030 (Vt. P.S.B. 1985), the Vermont Public Service Board indicated that, while the net incremental cost standard seems simple on the surface, it is difficult to apply in practice because of the difficulty of predicting what costs the utility would have incurred had it not interconnected with the QF. The Vermont Board solved the problem by adopting a presumption, rebuttable by the utility, that transmission system improvements which may be required when or after a project comes on line will be equal in cost to system improvements or replacements which would otherwise be necessary over the same period of time the QF is projected to be online. This is a persuasive precedent that should be looked to for guidance here.

E. <u>Under similar circumstances, in cases under the Federal Power Act, FERC has required rolled-in treatment.</u>

In a series of cases involving Western Massachusetts Electric Company, the QF's intended to wheel power over the Western Massachusetts system to another utility. As a result, FERC had jurisdiction to allocate Western Massachusetts's costs under the Federal Power Act ("FPA"). FERC distinguished between direct costs of interconnection (the direct connection and the feasibility and engineering studies), on the one hand, and grid upgrades (on transmission system lines and substations in the area "local" to the new generation), on the other, and held that, because the grid upgrades provided benefit to the transmission system generally, only the direct interconnection costs were to be directly assigned to the QF and that the grid upgrades were to be rolled into and recovered through the utility's transmission rates. *See Western Massachusetts Electric Company*, 77 F.E.R.C. P61, 268 (1996), *affirmed, Western Massachusetts Electric Co. v. FERC* 165 F.3d 922 (D.C. App. 1999). The FERC cited the Western Massachusetts decisions in Order Nos. 2003 and 2006.

Therefore, while those decisions were made under FERC's FPA rather than PURPA authority, they reflect a sensible ratemaking policy that upgrades to the grid beyond the point of interconnection should be presumed to have a system benefit and should thus be recovered in transmission rates, not interconnection cost charges. In other words, new generation should only be responsible for the costs of the new "driveway," not for the costs of "widening the highway."

F. A similar bright-line division on interconnection cost responsibility is a beneficial approach.

FERC's ruling in the Western Massachusetts cases that direct interconnection cost responsibility belongs to the QF, and "local" grid upgrades belonging to the utility provides an example of a bright-line division for interconnection cost responsibility. Such a bright-line division between "driveway" and "highway" costs encourages the development of new generation, by providing reasonable certainty about the costs required to bring new generation on line, and by preventing the shifting of investment burdens on to new generation that can be prohibitively expensive.

For example, in the portion of Texas not subject to FERC jurisdiction, a new generator is only responsible for the cost of interconnection facilities on its side of the point of interconnection, the cost of transmission voltage step-up transformers, and the cost of the studies that must be performed to ensure reliability. *See* 16 Tex. Admin. Code § 25.198; *Petition of the Electric Reliability Council of Texas for Approval of the Standard Generation Interconnection Agreement*, Docket No. 22052, *Order on Rehearing Approving the Standard Generation Interconnection Agreement* (Texas PUC, May 16, 2000). For generation 10 MWs or less in size that interconnects into an existing distribution rather than transmission system, the new generator is only responsible for the cost of interconnection facilities on its side of the point of interconnection and the cost of the reliability studies. *See* 16 Tex. Admin. Code § 25.211. These bright-line standards for what interconnection costs, a new generator is required to bear apply to all new generation, not just to wind and other QFs.

Through a variety of efforts, including the standardization of its interconnection process, Texas has seen significant amounts of new generation built in Texas, including wind power. *See* "New Electric Generating Plants in Texas," at http://www.puc.state.tx.us/electric/reports/index.cfm. Texas has even surpassed California in wind generation capacity. *See* http://www.windcoalition.org/news_page.php?tableName=News&id=36.

G. In seemingly undistinguishable circumstances Idaho Power has proposed to fund system upgrades, rather than assign them to Qualifying Facilities

On March 24, 2006 Idaho Power filed with the FERC a transmission rate case. *See* FERC Docket No. ER06—787-000; the entire filing may be viewed at http://www.oatioasis.com/ipco/index.html. In that proceeding, Idaho Power's System Planning Leader in the Grid Planning and Operations Department, Mr. Ron Schellberg, filed written pre-filed testimony which, among other things, explained the current and planned company funded transmission system upgrades that necessitated an increase in FERC jurisdiction rates. Mr. Schellberg testifies as follows:

> Q. Does the Company plan to continue to strengthen its transmission system?
>
> A. Yes. The Company has substantial transmission improvements under construction, and plans additional improvements in the near future. *The Company is implementing Borah West path upgrade next year (2007) to support planned wind and geothermal resource development in Burley/American Falls area.* This project is expected to cost approximately $37.4 million. (*See:* http://www.oatioasis.com/IPCO/IPCOdocs/Exhibit_IPC- 01_Schellberg_Testimony.pdf Emphasis Added).

While this testimony does not explain all the details of the proposed Borah path upgrade, it indicates, at a minimum, that there are circumstances in which Idaho Power makes rate-based transmission investments to support wind energy sources, rather than assigning those costs to the wind generator.

H. Rolled-in treatment of grid related up-grades is the least-cost approach for ratepayers.

As Cassia understands it, Idaho Power proposes to treat QF payments for grid upgrades as contributions or advances in aid of construction and to refund them over a period of time. Amounts refunded will then be added to Idaho Power's rate base. In the end, Idaho Power's customers will be responsible for the cost of the grid-related upgrades—either sooner through rates charged to native load and transmission customers for the rate-based transmission investment if Idaho Power bears all of the upgrade cost responsibility, or later through the inclusion of the QF refunds in the Idaho Power rate base.

The large, integrated, multi-state utility's cost of capital is obviously far less than the cost of financing available to smaller private developers. From a societal point of view, including the cost of grid related upgrades in the utility's rates now is less expensive for ratepayers than funding the upgrades with more expensive private capital now, and then refunding it later.

I. Assigning costs of grid upgrades to third parties allows Idaho Power to avoid prudence review of those costs.

Under normal circumstances, in the regular course of the rate making process, utility investments of the nature proposed here would be subject to prudence review in a general rate case at the time Idaho Power proposes including them in rate base. Among other things, the Commission would examine whether the investments were the least cost solution to the identified problem.

Under Idaho Power's proposal, the utility investments would not be added to rate base except incrementally over time, as refunds are made to the QFs. Therefore, the entire cost of the transmission upgrades would not be an issue in a single rate case. Instead, only small portions of the upgrade costs would be part of a particular rate proceeding. Within the available time and resources for resolving a rate case, other larger issues would command much more of the attention of the case participants and the Commission. The incremental refund amounts would thus largely escape prudence review.

Conclusion

The Commission should order Idaho Power to proceed with interconnection of Cassia and other QF's without assignment to them of any grid upgrade costs.

The Idaho Power proposal to make QF wind projects bear the $60 million cost of Idaho Power's grid upgrades creates a variety of issues, such different types of improper discrimination, and adverse ratemaking impacts on Idaho consumers. But most importantly, the Idaho Power proposal will thwart the development of new renewable generation that is on the verge of being installed in Idaho. Public policy favors renewable energy, including wind power. *See, e.g., Western Governors' Association Policy Resolution 06-10, "Clean and Diversified Energy for the West*" (June 11, 2006, Sedona, Arizona), found at http://www.westgov.org/wga/policy/06/clean-energy.pdf. Cassia urges the Commission to act promptly to clarify that QF's like Cassia are only responsible for the direct interconnection costs necessary to deliver the wind power into the existing grid, borrowing from the "driveway-only" precedents discussed above, so as to prevent what would be a public policy failure regarding renewable energy in Idaho.

DATED this 12 day of September, 2006.

Respectfully submitted,

MCDEVITT & MILLER LLP

Dean J. Miller
McDevitt & Miller LLP
420 W. Bannock
Boise, ID 83702
Phone: (208) 343-7500
Fax: (208) 336-6912

Counsel for
Cassia Wind Gulch Park LLC
and Cassia Wind LLC

CERTIFICATE OF SERVICE

I hereby certify that on the 13th day of September, 2006, I caused to be served, via the method(s) indicated below, true and correct copies of the foregoing document, upon:

Jean Jewell, Secretary	Hand Delivered	X
Idaho Public Utilities Commission	U.S. Mail	☐
472 West Washington Street	Fax	☐
P.O. Box 83720	Fed. Express	☐
Boise, ID 83720-0074	Email	☐
jjewell@puc.state.id.us		

Barton L. Kline	Hand Delivered	☐
Idaho Power Company	U.S. Mail	X
1221 West Idaho Street	Fax	☐
P.O. Box 70	Fed. Express	☐
Boise, ID 83707	Email	X
BKline@idahopower.com		

BY: Heather Hule, Legal Asst.

Western Electricity Coordinating Council

REMEDIAL ACTION SCHEME DESIGN GUIDE

prepared by the
Relay Work Group

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REMEDIAL ACTION SCHEME DESIGN GUIDE

EXECUTIVE SUMMARY

Remedial action schemes (RAS), also known as special protection systems (SPS) or system integrity protection systems (SIPS), have become more widely used in recent years to provide protection for power systems against problems not directly involving specific equipment fault protection. The terms SPS and RAS are often used interchangeably, but WECC generally and this document specifically uses the term RAS.

As electric systems grow and economics dictate certain system design and operating philosophies, the probability increases that local or system-wide problems not solvable by equipment-specific protection systems must be addressed. Remedial action schemes are applied to solve single and credible multiple-contingency problems. These schemes have become more common primarily because they are less costly and quicker to permit and build than other alternatives such as constructing major transmission lines and power plants.

Major applications of RAS include increasing power transfers, adding reactive support, utilizing reactive support available elsewhere within the region, and limiting the scale of cascading outages to ensure that bulk transmission system performance remains within WECC operating or performance requirements. RAS are generally designed to address specific problems such as equipment overloads, low voltages, or unsustainable generation/load patterns that arise following line or other equipment outages.

This Guide is a revision of the 1991 WSCC "Guide for Remedial Action Schemes." The NERC and WECC Standards have changed significantly since 1991. The Standards' changes were driven by the major WSCC outages in July and August 1996 with "reminders" from the outages in eastern North America and Italy in August and September 2003. These outages indicate that Standards compliance is necessary. This document is intended to help the RAS designer comply with these Standards. (The 1997 NERC and 2002 WECC Planning Standards Section III. F and 2005 NERC Standards PRC-012-0 through PRC-017-0 specifically apply to RAS).

ATTACHMENT
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REMAINDER OF DOCUMENT AVAILABLE ON REQUEST