SIXTH AMENDMENT TO WESTERN ELECTRICITY COORDINATING COUNCIL RELIABILITY CRITERIA AGREEMENT – CANADIAN LANGUAGE VERSION

This **SIXTH AMENDMENT TO WESTERN ELECTRICITY COORDINATING COUNCIL RELIABILITY CRITERIA AGREEMENT – CANADIAN LANGUAGE VERSION** ("Amendment") is entered into as of __________ ___, 2007 among the Western Electricity Coordinating Council, Inc. ("WECC") and Canadian member Transmission Operators ("Canadian Participating Transmission Operators") (collectively, the "Parties").

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RECITALS

WHEREAS, WECC and Canadian Participating Transmission Operators are parties to the Reliability Criteria Agreement dated as of August 1, 1999, as amended by the First Amendment to the Reliability Criteria Agreement dated as of July 1, 2000, by the Second Amendment to the Reliability Criteria Agreement dated as of November 1, 2000, by the Third Amendment to the Reliability Criteria Agreement dated as of May 18, 2001, by the Fourth Amendment to the Reliability Criteria Agreement dated as of August 1, 2003, and by the Fifth Amendment to the Reliability Criteria Agreement dated as of April 25, 2005 ("Agreement"); and,

WHEREAS, WECC and the Canadian Participating Transmission Operators desire to amend the Agreement to incorporate by reference and implement as reliability criteria any reliability standard developed by the Electricity Reliability Organization as approved by the Federal Energy Regulatory Commission and by the applicable Canadian Regulatory Authority; and

WHEREAS, on October 5, 2006, the Board of Directors of the WECC approved the changes to the Agreement set forth herein;

NOW, THEREFORE, in consideration of the agreements and covenants hereinafter set forth and intending to be legally bound hereby WECC and the Canadian Participating Transmission Operators hereby agree as follows:

1. The Agreement shall be amended by:

   a. adding the following sentence to the definition of "Control Area" in Section 2:

"As used herein, the term "Control Area" shall have the same meaning as the term "Balancing Authority Area" or "Balancing Authority," as applicable, as such terms are used in the NERC Standards."

b. adding the following definitions in Section 2:

"Bulk–Power System means facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability."

"ERO means the Electric Reliability Organization certified by FERC to develop mandatory Reliability Standards for the Bulk-Power System."

"Reliability Standard means any mandatory standard developed by the ERO and approved by FERC and the applicable Canadian Regulatory Authority to provide for the reliable operation of the Bulk-Power System in the applicable Province of Canada."

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c. adding the following new section 4.3:

4.3 Applicability of Criteria; Conflict with ERO Reliability Standards. Notwithstanding anything else in this Reliability Agreement, any reliability criterion set forth in Annex A shall be no longer in effect and shall be unenforceable upon the applicable Province of Canada effective date of an ERO Reliability Standard that establishes a standard addressing the same subject as such criterion.

d. replacing the definition of "NERC Standards" in Annex A, Section I with the following:

"**NERC Standards** means the standards and related requirements and measures contained in the NERC Reliability Standards for the Bulk Electric System of North America, as such may be amended from time to time."

e. adding the following new definition to Annex A, Section I:

"**NERC Transmission Operator** means the entity responsible for the reliability of the Bulk Power System in its jurisdiction, and that operates or directs the operations of transmission facilities in its jurisdiction."

f. adding the following title before the first paragraph in Annex A, Section II:

"A. Sanctions for Non-Compliance"

g. adding the following to the end of the first sentence in the first paragraph in Annex A, Section II:

"; provided, however, that no sanctions will be assessed for non-compliance with a criterion in Sections III, IV, and V if the Participant is sanctioned under an ERO Reliability Standard for the same action or non-action that resulted in non-compliance with such criterion in Sections III, IV, and V."

h. adding the following title immediately before the paragraph that reads: "The 'Specified Period and the 'Sanction Measure' are as specified below for each criterion." in Annex A, Section II:

"B. Specified Period and Sanction Measure"

i. replacing the word "Sanctions" in the first line of the second paragraph in the newly designated Annex A, Section II.B, with the following:

"Unless excused pursuant to Section II.A, sanctions"

j. replacing Section III.B.4 to Annex A in its entirety with the following:

"4. Compliance Standard

A Participant identified in Section III.B.1 must meet the Disturbance Control Standard specified in Section III.B.2 following all Disturbances. Compliance with the Disturbance Control Standard ("DCS") shall be measured on a percentage basis as set forth in BAL-002 of the NERC Standards (subject to the 15 minute recovery period specified in Section III.B.2)."

k. replacing the phrase "NERC Performance Subcommittee" in Section III.C.2 of Annex A with "NERC Operating Committee."

l. replacing the phrase “the NERC Performance Standard Training Document” in Section III.C.4 of Annex A with “BAL-001 of the NERC Standards.”

m. replacing the phrase “Section B.1.1.2 of the NERC ‘Performance Standard Training Document’” in Section III.D.2 of Annex A with “BAL-001 of the NERC Standards.”

n. replacing the phrase “the NERC Performance Standard Training Document” in Section III.D.4 of Annex A with “BAL-001 of the NERC Standards.”

o. replacing Sections III.J.1 and III.J.2 to Annex A in their entirety with the following:

“J. Operator Certification

1. Participants Subject to Criterion

This criterion applies to each Participant that is an operator of a Control Area, NERC Transmission Operator, Independent System Operator (ISO), Regional Transmission Operator (RTO), or Reliability Coordinator; provided, however, that monetary sanctions shall not be assessed against NERC Transmission Operators for non-compliance with this criterion for any incidents of non-compliance prior to January 1, 2007.

2. WECC Criterion

- Control Areas, NERC Transmission Operators, Independent System Operators, Regional Transmission Operators, and Reliability Coordinators that maintain control center(s) for the real-time operation and direct control of the interconnected Bulk Electric System shall continuously staff all real-time operating positions with NERC-Certified system operators.

Subject to the requirements and the exceptions explained below, certification is required for those System Operators in a position to make and/or carry out decisions, without review by higher authority, that could impact interconnected system reliability.

Entities requiring NERC-Certified System Operators

- Control Areas
- NERC Transmission Operators
- Independent System Operators
- Regional Transmission Operators
- Reliability Coordinators

Control Area, NERC Transmission Operator, Independent System Operator, Regional Transmission Operator, and Reliability Coordinator Positions requiring NERC-Certified System Operators

- Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System, or
- Positions that are directly responsible for complying with NERC Reliability Standards.

Control Area, NERC Transmission Operator, Independent System Operator, Regional Transmission Operator, and Reliability Coordinator Personnel required to be NERC-Certified

- All Personnel working in the control center for Reliability Coordinators filling positions requiring NERC-Certified System Operators;

- System Operators who:

  - are employed by, or on behalf of, a Control Area, NERC Transmission Operator, Independent System Operator, Regional Transmission Operator, or Reliability Coordinator, and are filling positions requiring NERC-Certified System Operators,

  - are employed by, or on behalf of, a Control Area, NERC Transmission Operator, Independent System Operator, Regional Transmission Operator, or Reliability Coordinator, and have the primary responsibility, either directly or through communication with others, for the real-time operation of the Western Interconnection, and

  - are employed by, or on behalf of, a Control Area, NERC Transmission Operator, Independent System Operator, Regional Transmission Operator, or Reliability Coordinator, and are directly responsible for complying with NERC Reliability Standards.

- System Operators on shift, employed by, or on behalf of, a Control Area, NERC Transmission Operator, Independent System Operator, Regional Transmission Operator, or Reliability Coordinator, including shift supervisors, and management personnel who direct the real-time actions of System Operators, filling positions requiring NERC-Certified System Operators, shall be NERC-Certified under the applicable area of responsibility (i.e., only NERC-Certified personnel for a particular type of power system may direct the real-time operation of such type of power system).

Certification Requirements are not intended to apply to substation or power plant operators, or to personnel who perform switching provided that the personnel performing the switching are supervised by on-shift NERC-Certified personnel.

Exception for new personnel (new trainee):

Any organization, otherwise required to have NERC-Certified operators shall not permit a new System Operator or new trainee that is not NERC-Certified to hold a System Operator position. Non NERC-Certified personnel shall not be permitted to work independently in positions requiring NERC-Certified System Operators.

While in training to become a NERC-Certified System Operator, an uncertified individual may work only in a non-independent position, shall not perform any duties related to operation of the Bulk Electric System unless directly overseen by a NERC-Certified System Operator on a one-on-one supervisory basis, and must be under the direct authority of a NERC-Certified System Operator at all times while on the job.

NERC Standards require all individuals in the positions referenced above must be NERC-Certified. To qualify for the NERC training exception for new personnel, the person needs to be truly in training and not filling a shift position that requires a NERC-Certified System Operator. The person may only work in a non-independent position, meaning that the individual is not filling a shift position that requires a NERC-Certified System Operator and has a NERC-Certified System Operator that is filling the shift position to monitor and approve all actions of the person in training. A NERC-Certified System Operator may only supervise one trainee per shift.

Period of Certification. The NERC System Operator Certification credential shall be valid for the period specified by NERC from the date of passing the certification examination.

a) **Recertification.** System Operators working in the positions requiring NERC Certification shall maintain their NERC Certification.

b) **Lapsed Certification.** If a System Operator's NERC Certification credential expires, the System Operator shall not be considered a NERC-Certified System Operator."

p. replacing the phrase "NERC Policy 3" in Sections III.M.1.b.1.c. and III.M.2.b.5 of Annex A with the phrase "the NERC Standards."

q. replacing Section III.M.2.b.1 to Annex A in its entirety with the following:

"1. The LCA's authority service has either not implemented E-tag or fails to maintain an availability of greater than or equal to 99.5% of the time during a calendar month pursuant to the NERC Standards."

r. replacing Section III.M.3.b.1 of Annex A in its entirety with the following:

"1. The TAE's approval service has not implemented or fails to maintain an availability of greater than or equal to 99.5% of the time during a calendar month pursuant to the NERC Standards."

s. deleting the phrase "TAE authority" each of the four times it appears in Section III.M.3.c in Annex A and inserting in place thereof "TAE."

t. deleting the phrase “events listed in Sections VI.B(1)-(4)” in Section VI.A in Annex A and inserting in place thereof “events listed in Sections VI.B(1)-(5).”

u. adding the following new Section VI.B.5 to Annex A:

“5. Participation in Field Testing

Any action taken or not taken by the Participant in conjunction with the Participant’s involvement in the field testing (as approved by either the WECC Operating Committee or the WECC Planning Coordination Committee) of a new reliability criterion or a revision to an existing reliability criterion where such action or non-action causes the Participant’s non-compliance with the reliability criterion to be replaced or revised by the criterion being field tested; provided that Participant’s non-compliance is the result of Participant’s reasonable efforts to participate in the field testing.”

v. replacing “ATTACHMENT I” to Annex A with the attached “ATTACHMENT I” (Table 2) to Annex A.

w. replacing “ATTACHMENT II” to Annex A with the attached “ATTACHMENT II” (Table 3) to Annex A.

2. This Amendment shall be filed with the appropriate Canadian Regulatory Authorities by each Canadian Participating Transmission Operator with a request that it be made effective on November 1, 2006, and the Amendment shall become effective for each Canadian Participating Transmission Operator on the date specified by the appropriate Canadian Regulatory Authority.

3. This Amendment may be executed in counterparts and each shall have the same force and effect as an original.

IN WITNESS WHEREOF, WECC and the Canadian Participating Transmission Operators have executed this Amendment, by their duly authorized officers or agents, as applicable, as of the day and year first above written.

WESTERN ELECTRICITY COORDINATING COUNCIL, INC.

By: William Chamberlain
Title: WECC Chair

BRITISH COLUMBIA TRANSMISSION CORPORATION

By: Martin Huang
Title: Senior V.P., System Operations and Asset Management

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

By: Renata Kurschner
Title: Director, Generation Management

INDEPENDENT SYSTEM OPERATOR, operating as ALBERTA ELECTRIC SYSTEM OPERATOR

By: ______________________
Title: ______________________

Deleted: Dale McMaster

Deleted: Vice President Operations and Reliability

By: ______________________
Title: ______________________

Deleted: David Erickson

Deleted: Senior Vice-President and Chief Financial Officer

FORTIS B.C., INC.

By: Dave Cochrane

Title: Manager, System Control

ATTACHMENT I
Table 2
Existing WECC Transfer Paths (BPTP)
(Revised February 1, 2006)

	PATH NAME*	Path Number	Operating Agent
1.	Alberta – British Columbia	1	BCTC/AESO
2.	Northwest – British Columbia	3	BCTC/BPA
3.	West of Cascades – North	4	BPA
4.	West of Cascades – South	5	BPA
5.	West of Hatwai	6	AVA/BPA
6.	Montana to Northwest	8	NWMT
7.	Idaho to Northwest	14	IPC
8.	South of Los Banos or Midway- Los Banos	15	CISO
9.	Idaho – Sierra	16	SPP
10.	Borah West	17	IPC
11.	Idaho – Montana	18	NWMT
12.	Bridger West	19	PAC
13.	Path C	20	PAC
14.	Southwest of Four Corners	22	APS
15.	PG&E – SPP	24	CISO
16.	Northern – Southern California	26	CISO
17.	Intmntn. Power Project DC Line	27	LADWP
18.	TOT 1A	30	WAPA
19.	TOT 2A	31	WAPA
20.	Pavant – Gonder 230 Kv Intermountain – Gonder 230 kV	32	SPP/LADWP
21.	TOT 2B	34	PAC
22.	TOT 2C	35	NEVP
23.	TOT 3	36	WAPA
24.	TOT 5	39	WAPA
25.	SDGE – CFE	45	CISO/CFE
26.	West of Colorado River (WOR)	46	CISO
27.	Southern New Mexico (NM1)	47	EPE
28.	Northern New Mexico (NM2)	48	PNM
29.	East of the Colorado River (EOR)	49	APS
30.	Cholla – Pinnacle Peak	50	APS
31.	Southern Navajo	51	APS
32.	Brownlee East	55	IPC
33.	Lugo – Victorville 500 kV	61	CISO/LDWP
34.	Pacific DC Intertie	65	BPA/LADWP
35.	COI	66	BPA/CISO
36.	North of John Day cutplane	73	BPA
37.	Alturas	76	SPP
38.	Montana Southeast	80	NWMT
39.	SCIT**		CISO
40.	COI/PDCI – North of John Day cutplane**		BPA

- For an explanation of terms, path numbers, and definition for the paths refer to WECC's Path Rating Catalog.

** The SCIT and COI/PDCI-North of John Day Cutplane are paths that are operated in accordance with nomograms identified in WECC's Path Rating Catalog.

ATTACHMENT II
Table 3
Existing WECC Remedial Action Schemes
(Revised March 1, 2006)

	Path Name*	**Path Number**	**RAS**	**Involved Parties**
1.	Alberta – British Columbia	Path 1	Remedial actions are required to achieve the rated transfer capability. Most involve tripping tie lines for outages in the BCTC system. East to West: For high transfers, generation tripping is required north of the SOK cutplane in Alberta.	BCTC/AESO
2.	Northwest – British Columbia	Path 3	Generator and reactive tripping in the BCTC system to protect against the impact caused by various contingencies during transfers between British Columbia and the Northwest.	BCTC/BPA
3.	West of Hatwai	Path 6	Generator dropping (Libby, Noxon, Lancaster, Dworshak); Reactor tripping (Garrison); Tripping of Miles City DC link.	AVA/BPA
4.	Montana to Northwest	Path 8	Tripping Colstrip by ATR (NWMT); Switching shunt reactors at Garrison 500 kV; Tripping the back-to-back DC tie at Miles City; Tripping Libby, and Noxon generation by WM-RAS (BPA).	NWMT/BPA
5.	Idaho to Northwest	Path 14	Jim Bridger tripping for loss of Midpoint – Summer Lake 500 kV line.	IPC
6.	Midway-Los Banos	Path 15	CDWR and PG&E pump load dropping north of Path 15. PG&E service area load dropping north of Path 15. PG&E service area generation dropping south of Path 15.	CISO
7.	Idaho Sierra	Path 16	Automatic load shedding is required when the Alturas line is open for loss of the Midpoint-Humbolt 345 kV line during high Sierra system imports.	SPP
8.	Bridger West	Path 19	Jim Bridger tripping for delayed clearing and multi-line faults; Addition of shunt capacitors at Jim Bridger, Kinport and Goshen and series capacitor bypassing at Burns.	IPC
9.	IPP DC Line	Path 27	IPP Contingency Arming System trips one or two IPP generating units.	LDWP

10.	TOT1A	Path 30	Bonanza and Flaming Gorge generation is tripped for loss of the Bonanza-Mona 345 kV line to achieve rating on TOT1A.	WAPA
11.	TOT2A	Path 31	For the Montrose-Hesperus 345 kV line outage with Nucla generation above 60 MW, the parallel Montrose-Nucla 115 kV line is automatically transfer tripped.	WAPA
12.	TOT2B	Path 34	Trip Huntington generation for loss of the Huntington-Pinto + Four Corners lines when parallel lines are heavily loaded.	PAC
13.	TOT5	Path 39	For an outage of the Hayden-Gore Pass 230 kV line, the lower voltage parallel path is tripped.	WAPA
14.	SDGE RAS	Path 44	RAS used to meet reactive margin criteria for loss of both San Onofre units.	SDGE
15.	SDGE – CFE	Path 45	The purpose of the RAS is to automatically cross-trip (transfer trip) the Miguel – Tijuana 230kV following the outage of Imperial Valley – Miguel 500kV line.	SDGE/CFE
16.	Southern New Mexico	Path 47	For double contingencies on the 345 kV lines defined in the path, WECC Operating Procedure EPE-1 is implemented.	EPE
17.	Pacific DC Intertie	Path 65	Northwest generator tripping; Series capacitor fast insertion; mechanically switched shunt capacitors	BPA/LDWP
18.	California – Oregon Intertie	Path 66	Northwest generator tripping; Chief Jo Brake insertion; Fort Rock Series Capacitor insertion; Northern California generator and pump load tripping; N. California series capacitor bypassing, shunt reactor or capacitor insertion; Initiation of NE\SE Separation Scheme at Four Corners.	BPA/CISO/APS
19.	Meridian 500/230 kV Transformers**		Following the loss of the Meridian 500/230kV transformers, RAS is used to comply with WECC Standards under high load conditions.	PAC

20.	Northern-Southern California	Path 26	Remedial action required to achieve the rated transfer capability. Midway area generation tripped for loss of any two of three Midway-Vincent 500 kV lines.	CISO
21.	PNM Import Contingency Load Shedding Scheme (ICLSS)	Path 48	ICLSS is a centralized load shedding scheme for low probability events such as simultaneous outage of the Four Corners-West Mesa (FW) 345 kV and San Juan-B-A (WW) 345 kV lines, as well as any unplanned disturbance affecting voltage in the Northern New Mexico transmission system.	PNM
22.	Valley Direct Load Trip (DLT)		RAS is required for the loss of the Serrano-Valley 500 kV line. About 200 MW of Valley load is tripped.	SCE
23.	South of Lugo N-2 RAS		RAS is required for the simultaneous double line outage of any combination of the Lugo-Mira Loma 1 (when looped), 2, and 3 500 kV lines and the Lugo-Serrano (when de-looped) 500 kV line.	SCE
24.	Lower Snake RAS		The RAS is required to protect for the double line outage of the Lower Monumental-Little Goose 500-kV lines. Generation is dropped at Little Goose and Lower Granite Powerhouses as well as key the WM RAS. An outage of the Little Goose – Lower Granite 500 kV lines will drop generation at Lower Granite Powerhouse and key the Western Montana RAS.	BPA
25.	Palo Verde – COI Mitigation Scheme	Path 66	Required to provide for safe operation of the COI for the loss of two units at Palo Verde Nuclear Generating Station (PVNGS). The RAS protects the PVNGS and Palo Verde Transmission System (PVTS) for faults at Palo Verde and subsequent outage of the Palo Verde – Westwing 500 kV lines.	SRP
26.	Palo Verde/Hassayampa RAS		Provides protection to the PVNGS and the PVTS for faults at Palo Verde and subsequent double line outage of the Palo Verde to Westwing 500 kV lines.***	SRP

27.	Sierra Pacific – PacifiCorp RAS	Path 76	Needed for loss of the 230 kV Malin-Hilltop line when heavily loaded unless automatic reclose is successful. The scheme closes the Hilltop 345 kV line reactor if pre-outage northbound flow is greater than 150 MW. For pre-outage southbound flow greater than 235 MW the Hilltop 345 kV line trips and the Hilltop 345 kV line reactors closes.	SPPC

* For an explanation of terms, path numbers, and definition for the paths refer to WECC's Path Rating Catalog.

** The Meridian 500/230 kV transformers are not included in the Path Rating Catalog. The RAS associated with the Meridian transformers is included in Table 3 because the failure of the RAS may result in cascading.

*** The Palo Verde/Hassayampa RAS is designed to prevent cascading problems throughout the WECC region. This scheme is not Path related and is not used to protect any specific WECC Path.