Exhibit No.:
Issue: Transmission Operations
Witness: Richard C. Kreul
Type of Exhibit: Direct Testimony
Sponsoring Party: UtiliCorp United Inc.
Case No.:

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

Richard C. Kreul

December 1999

Exhibit No. 24
Date 9-15-00 Case No. EM-2000-369
Reporter KF

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF RICHARD C. KREUL
ON BEHALF OF UTILICORP UNITED INC.

CASE NO.

INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Richard C. Kreul. I am employed by UtiliCorp United Inc. ("UtiliCorp"), within the operating group UtiliCorp Energy Delivery ("UED"), as Vice President of Transmission Services, a position I've held since October, 1996. I joined UtiliCorp in 1994 with UtiliCorp's acquisition of what is now known as UtiliCorp Pipeline Systems, Inc. ("UPL"), as President of UPL. My business address is 10700 East 350 Highway, P.O. Box 11739, Kansas City, MO 64138.

Q. For whom are you testifying in this case?

A. I am testifying on behalf of UtiliCorp and its operating divisions Missouri Public Service ("MPS"), WestPlains Energy-Kansas ("WPE-KS"), WestPlains Energy-Colorado ("WPE-CO"), and West Virginia Power ("WVP").

Q. Please describe your educational background.

A. I hold both a Bachelor of Science and a Master of Science in Mechanical Engineering from the University of Arkansas -- Fayetteville. I am a licensed Professional Engineer in the states of Arkansas, Texas, and Oklahoma. I have 20 years of experience in the energy industry. My responsibilities during the past three years include the management of UtiliCorp's electrical and natural gas transmission systems.

Q. Have you previously filed testimony before any state or federal agencies?

A. Yes, I have filed testimony before the Missouri Public Service Commission ("Commission") on behalf of Missouri Pipeline Company and Missouri Gas Company, subsidiaries of UPL.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to provide an overview and generally describe the configurations of high voltage transmission systems and their operations for both The Empire District Electric Company ("Empire") and UtiliCorp, as these entities are today, and as they are planned to be in the future after the proposed merger.

Q. Do you sponsor any Schedules associated with this application?

A. Yes. I am sponsoring the following: Schedule RCK-1 through Schedule RCK-4 which are high voltage transmission system maps of Empire and UtiliCorp's three domestic divisions that have transmission systems; Schedule RCK-5 illustrates voltage level and thermal limit information and data for all first tier interconnections of Empire and the three UtiliCorp operating divisions that have transmission; Schedule RCK-6 through Schedule RCK-9 are system schematic representations of all transmission voltage levels, loads and losses for Empire and the three primary UtiliCorp operating divisions; Schedule RCK-10 is a summary of a recent study of a direct high voltage interconnection between Empire and MPS; and Schedule RCK-11 which is a copy of UtiliCorp's Initial Comments in response to the Federal Energy Regulatory Commission's ("FERC") Notice of Proposed Rulemaking ("NOPR") on Regional Transmission Organizations ("RTO") filed on August 16, 1999.

Q. Were these schedules prepared by you or under your direction?

A. Yes.

DESCRIPTION OF EMPIRE SYSTEM

Q. Please generally describe the Empire high voltage transmission system.

A. Empire operates a control area in the Eastern Interconnected Grid providing service to approximately 143,555 customers, including four municipalities and two rural electric cooperatives (three points of delivery) in southwestern Missouri, northwestern Arkansas, northeastern Oklahoma, and southeastern Kansas. Empire's 161 kV system consists of segments from the Hickory County line near Cross Timbers, MO to the northeast; Ozark Beach, MO to the southeast; the Southwestern Electric Power Company ("SWEPCO") Flint Creek power station near Gentry, AR to the south; and the KG&E Neosho power station near Neosho, KS to the west. Empire is interconnected with Southwest Power Administration ("SWPA"), SWEPCO, Public Service of Oklahoma, GRDA, Arkansas Power & Light Company ("APL") and Western Resources ("WR"). Empire is a joint owner with SWEPCO, AEC, Grand River Dam Authority ("GRDA") and City Utilities of Springfield, MO ("CU") in a 345 kV line from GRDA's power plant in Mayes County, OK to Morgan, MO, whereby Empire owns approximately 22 miles of the line, extending from the Lawrence County/Greene County line to a point north of Monett, MO, in exchange for scheduling rights of 12.1% of the line's capacity. Empire is also contractually interconnected with SJLP and KCPL as a 12 percent or 80.85 MW co-owner in the Iatan power plant near Weston, MO. Exhibit No.____(RCK-1) illustrates the Empire high voltage transmission system and its control area interconnections.

Q. How would you characterize Empire's transmission system with respect to native load?

A. At the present time, the Empire high voltage transmission system is adequate for its own native load.

DESCRIPTION OF UTILICORP SYSTEMS

Q. Please briefly describe the transmission systems for the four domestic UtiliCorp divisions.

A. UtiliCorp has four non-contiguous, non-interconnected, domestic electric operations. MPS, WPE-KS, and WVP which are located in the Eastern Interconnected Grid; and WPE-CO, which is located in the Western Interconnected Grid.

Q. Please briefly describe the MPS system.

A. MPS operates a control area in the Eastern Interconnected Grid and provides service to approximately 193,000 customers – including eight wholesale customers -- in western and north central Missouri. MPS has direct high voltage interconnections with five utilities: KCPL, WR, UE, AEC, and the City of Independence, MO. It has a non-synchronous connection with Empire and KAMO, (a transmission cooperative in , MO, and OK), but these interconnects are operated normally open. MPS is a joint owner with KCPL and WR in a 345 kV interconnection from Wichita, KS to Sibley, MO. MPS is also a joint owner with KCPL in a 345 kV Missouri interconnection from Sibley to UE's Overton substation. MPS transmission rights through these interconnections are over approximately 58 miles of line in MPS' service territory from Stilwell, KS to UE's Overton substation. MPS owns a 8 percent or 174 MW share of the Jeffrey Energy Center located in the WR service territory, and has reserved transmission capacity through a Jeffrey Transmission Agreement with WR to deliver MPS energy from Jeffrey to MPS at its Stranger Creek interconnection with WR. MPS remotely operates its transmission system through a Supervisory Control and Data Acquisition ("SCADA") system from its Operations Center in Lee's Summit, MO. Schedule RCK-2 is the map that illustrates the MPS high voltage systems.

Q. Please briefly describe the WPE-KS system.

A. WPE-KS also operates a control area in the Eastern Interconnected Grid. WPE-KS provides service to approximately 67,000 customers -- including 23 wholesale customers -- in West Central Kansas. WPE-KS is interconnected to four other utilities: WR, Midwest Energy ("ME"), Sunflower Electric Power Corporation ("SEC"), and Southwestern Public Service Company ("SPS"). Like MPS, WPE-KS is also an 8 percent or 174 MW co-owner in the Jeffrey Energy Center located in WR's service territory, and has a reserved Jeffrey Transmission Agreement with WR to deliver WPE-KS 174 MW of energy to its East Manhattan interconnection with WR. Similar to MPS, WPE-KS remotely operates its transmission system through a SCADA system from its Operations Center in Great Bend, Kansas. Schedule RCK-3 is a map that illustrates the WPE-KS high voltage systems.

Q. Please briefly describe the WPE-CO system.

A. WPE-CO is located in the Western Interconnected Grid, and serves approximately 80,000 retail customers in southeastern Colorado, including one wholesale customer. It is operated under the Public Service Company of Colorado ("PSCO") control area. WPE-CO has direct interconnections with PSCO, the City of Colorado Springs, CO, Western Area Power Administration ("WAPA"), Tri-State Generation and Transmission Association ("TS") and the Arkansas River Valley Power Authority ("ARPA"). There is no interconnection between WPE-CO and WPE-KS, nor does UCU have any firm transmission rights across any ties between the Western and Eastern grids. Similar to MPS and WPE-KS, WPE-CO remotely operates its transmission system through a

SCADA system from its Operations Center in Pueblo, CO. Schedule RCK-4 is a map that illustrates the high voltage WPE-CO system.

Q. Please briefly describe the WVP.

A. The WVP serves approximately 25,000 retail customers in south central West Virginia. WVP does not have any generation or high voltage transmission facilities, and does not operate any control area services. It is a distribution utility, directly connected to -- and served as a full requirements wholesale customer by – Appalachian Power Company, a subsidiary of American Electric Power Company ("AEP"). UtiliCorp has recently announced plans to sell this property to Allegheny Energy, Inc.

Q. You said that both MPS and WPE-KS are interconnected with WR, and receive energy from the Jeffrey Energy Center through transmission agreements with WR. Doesn't this imply that MPS and WPE-KS are interconnected?

A. No. Firm energy only flows *from* the Jeffrey Energy Center on WR, either *to* the MPS Stranger Creek interconnection, or *to* the WPE-KS East Manhattan interconnection.

Q. Can those Transmission Agreements with WR be used to provide wholesale transmission service to third parties other than MPS or WPE-KS?

A. No. The two firm transmission reservations embedded in the Jeffrey Transmission Agreements are specifically for the two 8 percent, or 174 MW each, shares of Jeffrey Energy Center generation. Those two separate shares, and the respective transmission rights, are operated at very high capacity factors for base load power and energy. WR does allow the combined Jeffrey transmission entitlements of MPS's 174 MW and WPE-KS's 174 MW, a total of 348 MW, to be transmitted to either MPS at Stranger Creek or WPE-KS at East Manhattan, in total or portions thereof.

UTILICORP'S OPEN ACCESS TARIFFS

Q. Do Empire and the three UtiliCorp operating divisions have Open Access Transmission Tariffs on file with the Federal Energy Regulatory Commission ("FERC") and in place in the marketplace?

A. Yes. The Empire tariff is titled "Open Access Transmission Service Schedule OATS" and was filed with FERC in Docket No. OA96-206-000. That tariff is a result of settlement negotiations between all concerned parties. FERC approved Empire's open access tariff on August 1st, 1997, with an effective date of July 9th, 1996. For customers who had service agreements in effect at that time, the Company Tariff would not be applicable until such time as a rate increase is filed. Additionally the Empire participates in the Southwest Power Pool ("SPP") regional tariff. The SPP filed on December 19th, 1997 its own open access tariff for Regional pool-wide short-term transmission services. FERC approved the SPP tariff on June 1st, 1998. On December 1st, 1998 the SPP filed an amended open access tariff to include long-term point-to-point transmission services. FERC accepted the amended tariff effective April 1st, 1999. As a result, of these two tariffs, transmission services originating in the Empire service territory and not entering another SPP member's zone would be served under Empire's own tariff. Transmission loads originating in the Empire service territory zone and entering or crossing another SPP member's zone would be served under the SPP tariff, except that all long-term point-to-point transmission services contracts entered into prior to April 1st, 1999 would continue to be served under the Empire's own open access tariff. All four UtiliCorp domestic divisions have Open Access Transmission Tariffs in place. An updated application was made for MPS, WPE-KS, and WPE-CO on June 7, 1999 in FERC

Docket No. ER99-3163-000.

Q. Does the FERC Docket No. ER99-3163-000 include the WVP ?

A. No.

Q. How were the Open Access Transmission Tariffs developed for Empire and the three UtiliCorp divisions?

A. The Order 888 compliance tariffs for Empire were prepared in a conventional cost of service manner, with all facilities classified as transmission in accordance with the FERC Uniform System of Accounts included in the determination of transmission costs. The Empire tariff is not two tiered like the UtiliCorp tariffs; no distinction is made in the Empire tariff for multiple voltage levels. All high voltage transmission in the Empire system is treated as one electrified grid. The Empire tariff includes separate ancillary service rates for (i) Scheduling, System Control and Dispatch Service, (ii) Reactive Supply and Voltage Control from Generation Sources, (iii) Regulation and Frequency Response Service, (iv) Operating Reserves – Spinning, and (v) Operating Reserves – Supplemental. The sixth ancillary service charge (vi) Energy Imbalance Service contains a formula keyed to on-system fuel, purchased energy, less exchange energy, energy losses and net energy delivered to derive an average monthly cost in cents per kWh. The Empire open access tariff language for Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service is this Commission's pro forma tariff language.

The approach of developing UtiliCorp's Order 888A compliance tariffs for MPS, WPE-KS and WPE-CO have some differences from Empire's approach. In those filings, the radial facilities were not considered as a part of the transmission function for the MPS, WPE-KS and WPE-CO systems, resulting in lower open access transmission rates than would have been developed if all facilities (which included radial facilities) previously classified as "transmission" had been included in the rates. The open access filing included separate tariffs for each of the three UtiliCorp divisions, with the tariff language for these three divisions being FERC's pro-forma tariff. The rate structure in these three tariffs are for 345/161 kV and 69/34 kV deliveries for MPS; 115 kV/above and 34 kV for WPE-KS; and 115 kV and 69 kV for WPE-CO. All three tariffs contain separate ancillary generation charges for (i) Scheduling, System Control and Dispatching, (ii) Reactive Supply and Voltage Control from Generation Sources Service, (iii) Regulation and Frequency Response Service, (iv) Energy Imbalance Service, (v) Operating Reserve – Spinning, and (vi) Operating Reserve – Supplemental.

Q. If the proposed merger occur, will Empire and MPS be combined into one control area, or remain separate?

A. The two systems may be operated as a single regional control area after the two companies are merged.

Q. If the Empire and MPS control areas are combined, will the open access transmission tariffs be integrated?

A. Yes, that currently is the plan. With Empire and MPS interconnected and functioning as one control area, it is only logical that the two transmission entities be operated as one, with one Open Access Transmission Tariff. Depending upon the RTO development in the region, it may be possible to place all the MPS and Empire transmission facilities under an RTO and avoid the need to build additional transmission facilities by subscribing to the RTO's network service. If the RTO development does not provide for this possibility, then a transmission line will be constructed between the MPS and Empire systems. I'll also speak more about that later in this testimony.

Q. You said the merged Empire and MPS systems would possibly function as one regional control area. Would you please explain?

A. Yes. Ultimately, the transmission systems of both entities will be operated from the MPS Operations Center in Lee's Summit, MO, with the required SCADA system additions. Additions to the EMS/SCADA system will need to consolidate the Empire/UtiliCorp systems at an approximate cost of one million dollars. These changes provide for the gathering of SCADA data from the Empire power plants and third party tie-lines. In order to minimize costs, the existing RTUs at Empire will be converted to a common protocol for scanning by the UtiliCorp SCADA master station, rather than changing out the existing RTUs. Data will be brought into the UtiliCorp Lee's Summit Operations Center ("LSOC") by communications lines through multiplex and microwave equipment. Additional system workstations are included for the existing UtiliCorp EMS at the Empire site and the LSOC site.

Q. What effects will this change have on transmission safety and reliability?

A. Transmission system safety and reliability will be maintained. For the most part, it is anticipated that the same personnel who are operating and maintaining the existing Empire and MPS transmission systems will operate and maintain the consolidated systems, with the only exception being that the generation dispatch and transmission system operations will be carried out from the MPS Operations Center in Lee's Summit, MO. The same high standards of safety that both companies have demonstrated in the past will not be disturbed.

Q. You said that one of several possibilities for interconnecting Empire and MPS was to construct a transmission line between the two systems, and you have conducted a study of such an interconnection between Empire and MPS. Would you please explain that study?

A. Yes. Schedule RCK-10 illustrates the existing Empire and MPS 161 kV and 69 kV systems, and various construction options that are being considered. If UtiliCorp and Empire determine that a direct interconnection is warranted, the existing Empire transmission system has two 161 kV and two 69 kV lines that extend toward the MPS system that could provide possible interconnection points. Although UtiliCorp and Empire have considered several options for effectuating the interconnections, UtiliCorp and Empire currently favor the option of constructing a 161 kV line from south of the existing MPS Nevada Substation to the Empire Asbury power plant.

Q. In discussing the plans for interconnecting UtiliCorp's and Empire's systems, you identified the preferred options "if UtiliCorp and Empire determine that a direct interconnection is warranted." Under what circumstances might UtiliCorp and Empire determine that a direct interconnection is not warranted?

A. An alternative to construction of the interconnection facilities would be for UtiliCorp's and Empire's operations to join an RTO. If an RTO were developed that could make this possible and UtiliCorp and Empire determined that additional transmission construction is not necessary, UtiliCorp and Empire would consider integrating operations by taking network transmission service under an RTO tariff. In determining whether to integrate UtiliCorp's and Empire 's Missouri operations in this manner, UtiliCorp and Empire will consider whether taking such service from an RTO would result in inadequate transmission capacity for any entity that is transmission dependent with respect to

UtiliCorp and Empire. UtiliCorp and Empire will not effectuate any interconnection plan that would result in reducing Available Transfer Capabilities ("ATC") into or out of UtiliCorp's and Empire 's systems below the level needed for a transmission dependent entity to import energy to serve its load or to export energy from existing generation.

Q. What impact will this merger have on the transmission employees of both MPS and Empire?

A. It is anticipated that most transmission operations and maintenance personnel will stay in place, except for system operations, which will eventually be moved to the MPS Operations Center in Lee's Summit.

<u>REGIONAL TRANSMISSION ORGANIZATIONS ("RTO's")</u>

Q. You mentioned earlier in your testimony that UtiliCorp is giving serious consideration to how the Open Access tariffs will be structured for the merged Empire and MPS pending development of area RTO's. What are UtiliCorp's views on RTO's?

A. UtiliCorp is a strong supporter of RTO's , and filed Initial Comments in response to the FERC NOPR on RTO's on August 16, 1999 which gives more detailed discussions of our views For convenience, we attach that exact filing in Schedule RCK-11which includes the key characteristics in the formation and the operation of an RTO and addresses the questions of regional control and reliability.

Q. If this Commission ultimately decides that RTO's are in order, which RTO will the Empire/MPS merged systems join?

A. That really depends on what RTO(s) develop in the region. If an RTO turns out to be the Eastern Interconnected Grid, the Western Interconnected Grid and the Electric Reliability Council of Texas ("ERCOT"), then the merged Empire/MPS systems, WPE-KS would join the Eastern Interconnected Grid. If the RTO's turn out to be the existing North American Electric Reliability Council ("NERC") regions, then the merged Empire/MPS systems and WPE-KS would most likely join either the Mid-Continent Area Power Pool ("MAPP") RTO or the Southwest Power Pool ("SPP") RTO. There is also the Midwest ISO to the east of MPS, and consideration is being given to it.

Q. Does this complete your direct testimony at this time?

A. Yes, it does.

The Empire District Electric Company Interconnections

Name of System Interconnected to ED	TIE (METER) LOCATION Substation	Owner	State	kV	OTHER END OF TIE LINE(S) Substation	State	kV	THERMAL RATING OF (1) LINE (MVA) 30° C Rise	50° C Rise	NOMINAL TIE RATING (MW)
Arkansas Power & L	Powersite 312	EDE	MO	161	AP&L Omaha	AR	161	121	165	150
1-807-536-6935 (5)										
Associated Electric C	Morgan	AEC	MO	161	EDE Dadeville	MO	161	217	270	200
1-417-885-9200 (5), alternate ring down 2001(5)										
	Reeds Spring	EC/KAMO	MO	161/69	EDE Powersite	MO	161	Transformer Limit of 75 MVA		75
					EDE Aurora	MO	161			
	Monett	EDE	MO	69	KAMO Verona	MO	69	56	70	50
	Neosho	EDE	MO	161/69	KAMO Neosho	MO	69	Transformer Limit of 53 MVA		50
					KAMO Cassville	MO	69			
	Jamesville	EDE	MO	69	Blackhawk Jct.	MO	69	56	70	50
	Stockton 418	EDE	MO	161/69	AEC Stockton	MO	161	Transformer Limit of 75 MVA		75
					MPS Nevada					
Grand River Dam Au	Miami	GRDA	OK	161	EDE Hockerville	OK	161	Limited by CT's to 170 MVA		170
1-918-825-1053 ext 1101 (5), alternate ring down - pickup (5)										
	Fairland	EDE	OK	69	GRDA Miami	OK	69	56	69	60
					GRDA Afton	OK	69			
Kansas City Power &	Marmaton	KG&E	KS	161	KG&E Litchfield	KS	161	217	270)	
1-816-654-1242 (5)									)	
Kansas Gas & Elect	Litchfield	KG&E	KS	161	EDE Asbury	KS	161	217	270)	250
1-785-575-6051 (5)										
	Neosho Plant	KG&E	KS	161	EDE Riverton	KS	161	195	244	200
Public Service Comp	Grove	PSO	OK	138/161	EDE Noel	MO	161	Transformer Limit of 100 MVA		100
(Central & South West)										
1-214-777-2149 (5)	Hockerville	EDE	OK	161/138	PSO Vinita	OK	138	Transformer Limit of 100 MVA		100
Southwestern Electr	Flint Crk Plant	SWEPCO	AR	161	EDE Decatur	AR	161	217	270	200
(Central and South West)										
1-214-777-2149 (5)										
Southwestern Powe	Carthage	SWPA	MO	161	EDE Asbury	MO	161	217	270)	
1-417-881-3363 (5), alternate ringdown - 2606 (5)					EDE Atlas Jct.	MO	161	180	224)	200
	Neosho 335	SWPA	MO	161	EDE Neosho	MO	161	134	166)	
	Neosho 335	SWPA	MO	161	EDE Tipton Ford	MO	161	134	166)	120
	Table Rock Dam	SWPA	MO	161	EDE Powersite	MO	161	217	270	200
	LaRussell	EDE	MO	161	SWPA Carthage	MO	161	180	224)	
					SWPA Springfield	MO	161	180	224)	200

NOTES

(1) Thermal rating of line is not necessarily the transfer capability of the tie

(2) Empire is joint owner in 345 kV line with SWEPCO, AEC, GRDA and CU-Springfield.
Empire has reserved use of 150 MW for scheduling over this line with these systems.

(3) By contract agreement Empire may schedule with PSO (Central and South West) over the 161 kV GRDA tie.

(4) Tie with KCP&L is at KG&E Marmaton, metering is with KG&E: KCP&L line limit is 150/160 MW.

(5) Phone numbers listed are dispatch numbers used for switching transmission.

Missouri Public Service Interconnections

Interconnecting Line/Transformer								
From	To	Inter-connecting Utility	Line Ownership*	Thermal Line Rating** MVA	Line Voltage KV	Normal Open/ Closed	Thermal Capacity of Inter-connection MVA	Limiting Device
Archie 161 kV Substation Bus	Montrose Plant	KCPL	KCPL	224	161	Closed	448	Montrose and Stilwell Line Capacity
	Stilwell Substation	KCPL	KCPL	224	161	Closed		
	Adrian Substation		MPS	251	161	Closed		
	Harrisonville Substation		MPS	251	161	Closed		
Martin City 161-69 kV Substation Bus	Martin City (KCPL)	KCPL	KCPL	293	161	Closed	301	Grandview East Line and Transformer Capacity
	Southtown	KCPL	KCPL	224	161	Closed		
	Grandview East		MPS	251	161	Closed		
	161-69 kV Transformer		MPS	50	161-69	Closed		
Roanridge Substation Bus	Weatherby	KCPL	KCPL	273	161	Closed	301	TWA Line and Transformer Capacity
	Nashua	KCPL	KCPL	293	161	Closed		
	Barry	KCPL	KCPL	293	161	Closed		
	TWA		MPS	251	161	Closed		
	161-69 kV Transformer		MPS	50	161-69	Closed		
Duncan Road Substation	KCPL Duncan 60 kV Bus	KCPL	KCPL	60	161-69	Closed	60	161-69 kV Transformer
Sibley 161 kV Substation	Eckles Road Substation	IPL	IPL	251	161	Closed	251	Eckles Road Line
Nashua Substation	KCPL Nashua Substation	KCPL	MPS, KCPL	335	161	Closed	335	Substation Bus
Sedalia West 161 kV Substation	Norton Substation	AECI	AECI	111	161	Closed	111	Norton Line Wave Trap
Butler 161-69 kV Substation	161-69 kV TRansformer	AECI	AECI	50	161-69	Closed	50	Transformer Capacity
Platte City Substation	Stranger Creek Substation	WR	MPS, WR	400	161	Closed	400	345-161 kV Transformer at Stranger Creek
Sedalia East Substation	Overton 345-161 kV Substation	AE	MPS, AE	251	161	Closed	251	Transmission Line
AECI Clinto 161 kV Substation Bus	Sedalia West 161 kV Substation	AECI	MPS	251	161	Closed	351	Transmission Line and 161-69 kV Transformer
	MPS 161-69 kV Substation	AECI	AECI	100	161	Closed		
Liberty 69 kV Substation	Claycomo Substation	KCPL	KCPL, MPS	55	69	Closed	55	Transmission Line
Concordia 69-34 kV Substation	Sweet Springs Substation	KCPL	KCPL, MPS	8.5	34	Open	11	Transmission Line
Warsaw 69 kV Substation	Hermitage Substation	EDE	MPS, EDE	37	69	Open	37	Transmission Line
Blue Ridge 69 kV Substation	ILP Substation N	IPL	IPL, MPS	35	69	Open	35	Transmission Line
Eldorado Springs SW Tower	RUS Eldorado Springs Substation	AECI	MPS	55	69	Open	55	Transmission Line
Lamar 69 kV Substation	Boston Corners	EDE	MPS	27	69	Open	27	Transmission Line
Mayview Tap	Amoco Pipeline	KCPL	KCPL	71	69	Closed	71	Transmission Line

*Line ownership is by specific sections, usually changing at the existing service area boundry.
** Summer peak rating.

Utility Names:
MPS - Missouri Public Service Division of UtiliCorp United Inc.
KCPL - Kansas City Power & Light Company
IPL - City of Independence Department of Power & Light
EDE - The Empire District Electric Company
AECI - Associated Electric Cooperative, Inc.
AE - AmerenEnergyUE
WR - Western Resources

WestPlains Energy - Kansas Interconnections

Interconnecting Line/Transformer From	To	Inter-connecting Utility	Line Ownership*	Thermal Line Rating MVA	Line Voltage KV	Normal Open/ Closed	Thermal Capacity of Inter-connection MVA	Limiting Device
Harper Substation	Gill Substation	WR	WR, WPE-Ks	110	138	Closed	110	Transmission Line
WR/KPL St. John Substation	Hutchinson Substation	WR	WR	80	115	Closed	120	Transmission Lines to Larned and Hutchinson
	Larned Substation	WR	WR	40	115	Closed		
	Mullergren Power Plant		WPE-Ks	91	115	Closed		
	Pratt Substation		WPE-Ks	91	115	Closed		
Greenleaf Substation	Knobhill Substation	WR	WR, WPE-Ks	91	115	Closed	91	Transmission Line
Mullergren 230 kV Bus	Circle Substation	WR	WPE-Ks	320	230	Closed	320	Transmission Line
Concordia West Substation	East Manhattan	WR	WR, WPE-Ks	205	230	Closed	205	345-230 kV Transformer
Cimarron Power Plant	North Cimarron	SEC	SEC	133	115	Closed	133	Transmission Line
Mullergren 239 kV Bus	Heizer 115 kV Bus	MEI	WPE-Ks, WR	110	230-115	Closed	110	230-115 kV Transformer
Plainville Substation	Hays Substation	MEI	MEI, WPE-Ks	133	115	Closed	133	Transmission Line
Liberal Substation	Texas County Substation	SPS	SPS, WPE-Ks	112	115	**Closed	112	Transmission Line
Spearville 230 kV Bus	Spearville 345 kV Bus	SEC		336	345-230	Closed	336	345-230 kV Transformer

*Line ownership is by specific sections, usually changing at the existing service area boundry.
**A phase shifting transformer was installed during the Spring of 1996 that allowed this tie to be closed.

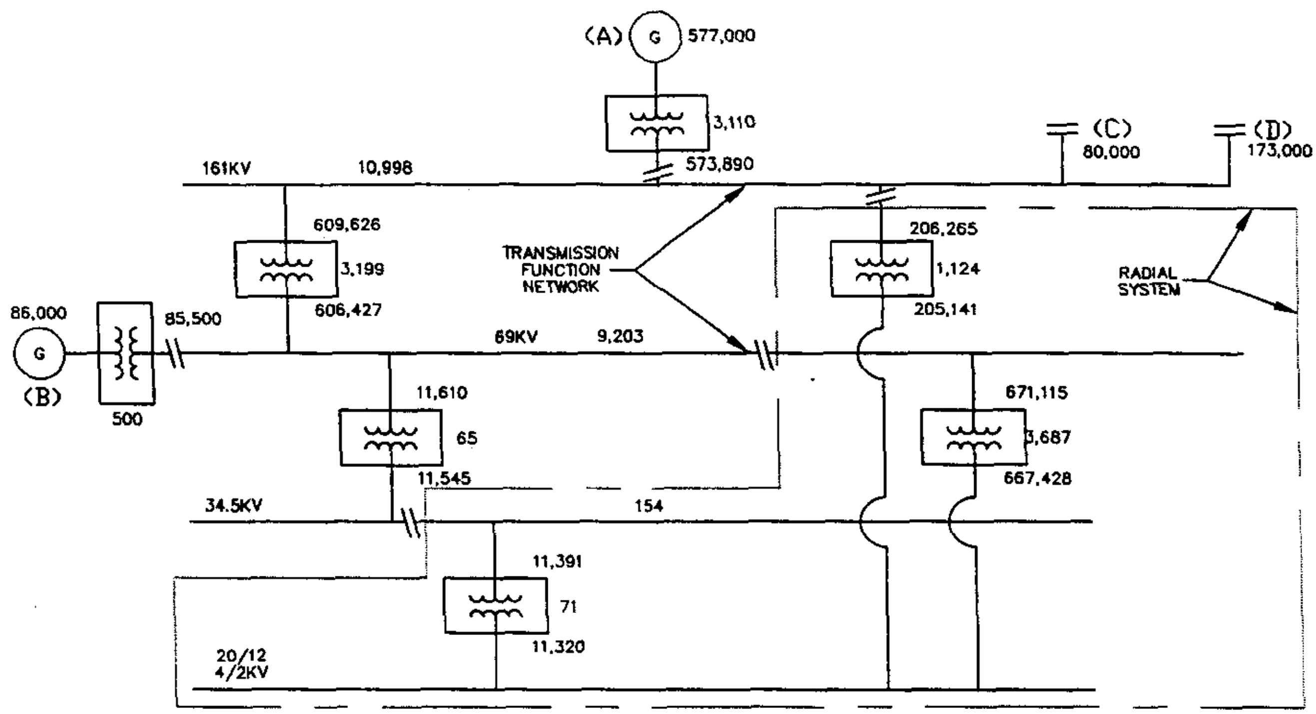
Utility Names:
WPE-Ks - WestPlains Energy - Kansas Division of UtiliCorp United Inc.
WR - Western Resources
SEC - Sunflower Electric Cooperative
MEI - Midwest Energy, Inc.
SPS - Southwestern Public Service Company (in the Western Interconnected Grid)

WestPlains Energy - Colorado Interconnections

Interconnecting Line/Transformer From	To	Inter-connecting Utility	Line Ownership*	Thermal Line Rating** MVA	Line Voltage KV	Normal Open/ Closed	Thermal Capacity of Inter-connection MVA	Limiting Device
Reader Substation Bus	Comanche 115 kV Bus	PSCO	PSCO	217	115	Closed	217	Transmission Line
West Station Substation	Midway WAPA Substation Bus	WAPA, CoSpg TS	WPE-Co	115	115	Closed	115	Transmission Line
Canon Plant Substation	Poncha Substation	PSCO	WPE, PSCO	133	115	Closed	133	Transmission Line
West Station	Walsenburg	TS	TS	136	115	Closed	136	Transmission Line
PSCO Midway Substation	West Station	PSCO	WPE, PSCO	115	115	Closed	100	230-115 kV Transformer
	Boone Substation	PSCO	WPE, PSCO	115	115	Closed		
PSCO Boone Substation	PSCO Midway Substation	PSCO	WPE, PSCO	115	115	Closed	150	230-115 kV Transformer
	WPE-Co LaJunta Substation	PSCO	WPE-Co	115	115	Closed		
	WPE-Co Boone Tap	PSCO	WPE-Co	33	115-69	Closed		
LaJunta Substation	Las Animas Substation	ARPA	WPE, ARPA	63	69	Open	63	Transmission Line

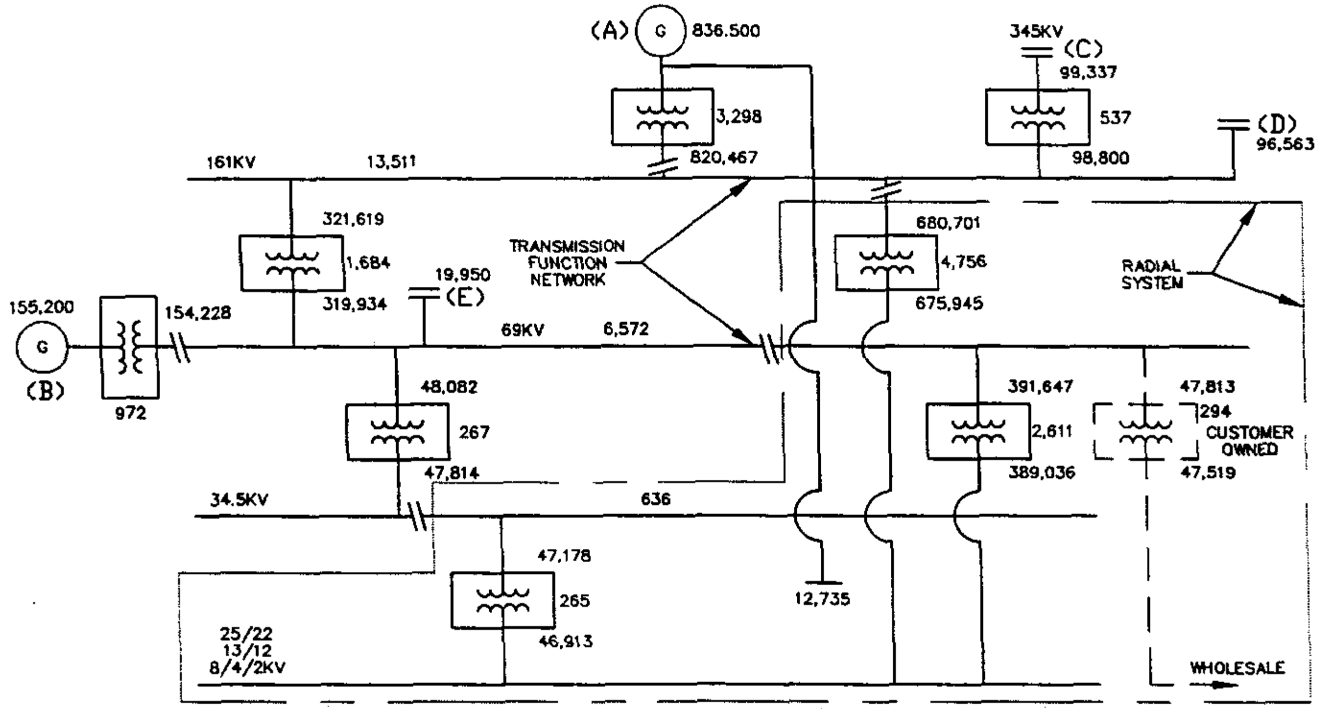
*Line ownership is by specific sections, usually changing at the existing service area boundry.

Utility Names:
WPE-Co (WPE) - WestPlains Energy-Colorado Division of UtiliCorp United Inc.
PSCO - Public Service Company of Colorado
CoSpg - City of Colorado Springs
TS - Tri-State Generation and Transmission Association
ARPA - Arkansas River Valley Power Association
WAPA - Western Area Power Administration



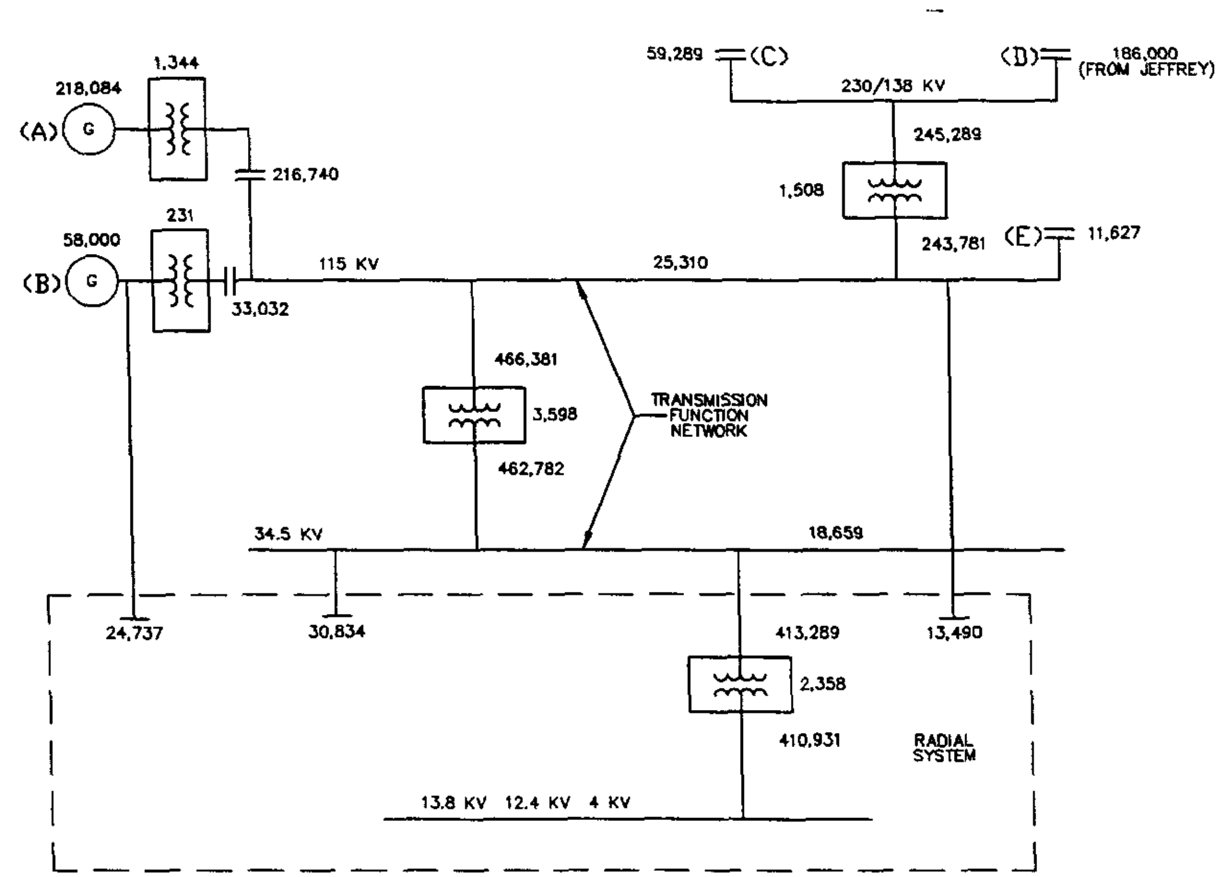
(A) Asbury, Riverton, Energy Center, State Line, Ozark Beach
(B) Riverton
(C) Iatan (EDE Share)
(D) APL(Entergy), AEC, GRDA, KCPL, KGE, PSO, SWEPCO, SPA

					DRAWN	DATE
					CAD REF.	CHK. BY
				1998 SUMMER 1CP LOADS VALUES IN KW EMPIRE DISTRICT ELECTRIC	W.O. NO.	
NO.	BY	DATE	DESCRIPTION		SCALE	
					SHEET OF	



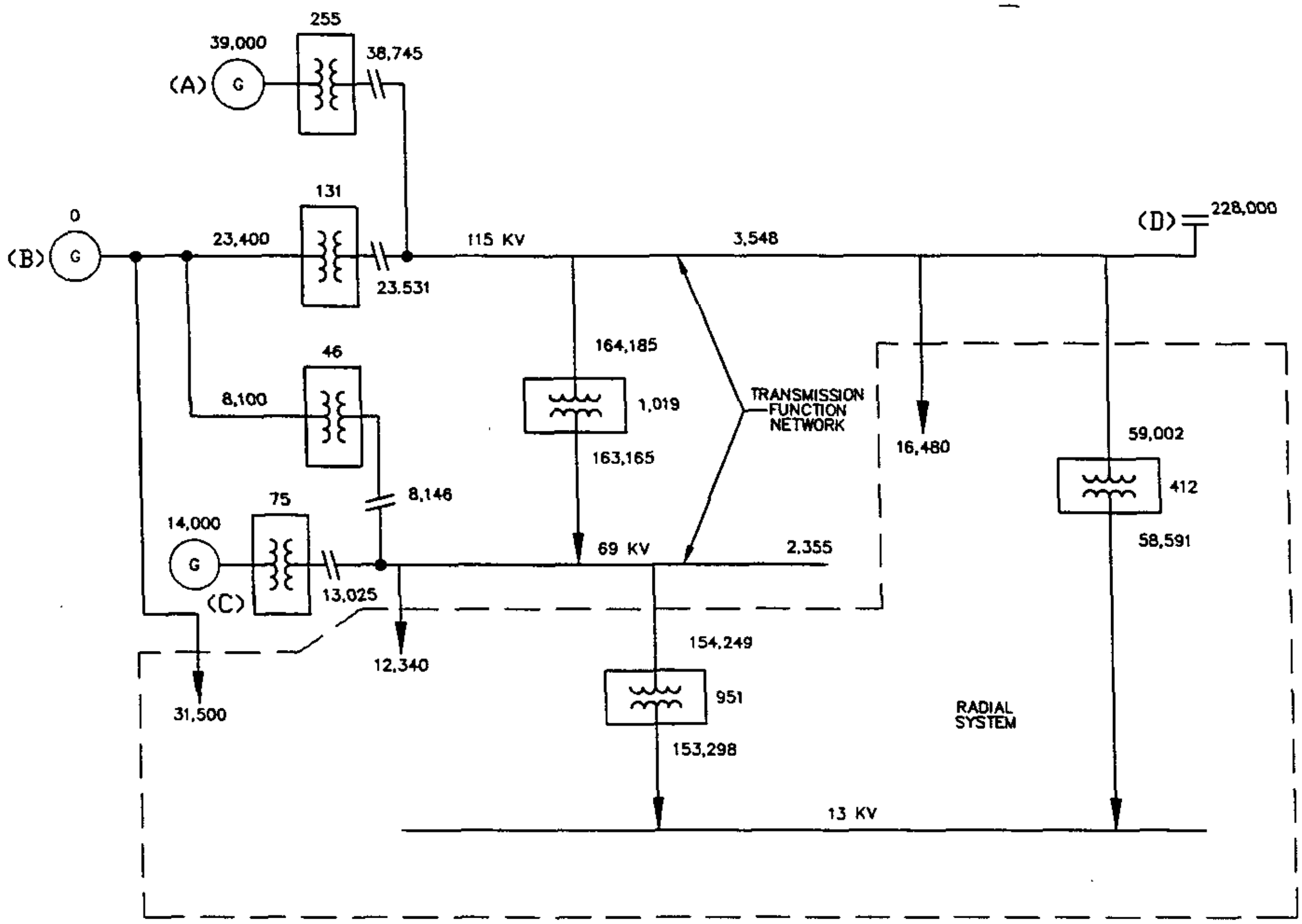
(A) Jeffrey, Sibley, Greenwood, KCI
(B) Ralph Green, Nevada
(C) KCPL, UE
(D) KCPL, UE, AEC
(E) AEC

NO.	BY	DATE	DESCRIPTION	1998 SUMMER 1CP LOADS VALUES IN KW MISSOURI PUBLIC SERVICE	DRAWN	DATE
					CAD REF.	CHK. BY
					W.O. NO.	
					SCALE	
					SHEET OF	



(A) Judson Large, Mullergren
(B) Cimarron River
(C) WR, Sunflower
(D) Jeffrey
(E) MWE, SPS, WR, Sunflower

					DRAWN	DATE
					CAD REF.	CHK. BY
				1998 SUMMER ICP LOADS VALUES IN KW WEST PLAINS ENERGY (KANSAS)	W.O. NO.	
NO.	BY	DATE	DESCRIPTION		SCALE	
					SHEET OF	



(A) Canon City
(B) Pueblo Steam
(C) Pueblo Diesel, Rocky Ford
(D) WAPA, Tri-State, PSCO, ARPA, Colorado Springs

NO.	BY	DATE	DESCRIPTION

1998 SUMMER ICP LOADS
VALUES IN KW
WEST PLAINS ENERGY (COLORADO)

DRAWN	DATE
CAD REF.	CHK. BY
W.O. NO.	
SCALE	
SHEET OF	

I. INTRODUCTION

The purpose of this study was to determine the preferred option for connecting (either physically or contractually) the UtiliCorp United (UCU) electrical transmission system with the Empire District (EDE) electrical transmission system. Four options for achieving this objective are discussed in this report.

Two categories of options were considered. The first category of options were options that were actual physical interconnections between the two systems. The second category of options were options that involved a contractual interconnection or a combination of physical/contractual interconnections.

Each option is discussed separately in the body of this report with regards to contingency analysis, estimated costs, and MW losses.

II. CONTINGENCY ANALYSIS

Loadflow models were created to simulate the existing transmission system. Initial loadflows were based on the year 2003 Southwest Power Pool summer peak models. Contingency analysis was performed for the existing system and each option to examine the transmission system's ability to perform adequately during a single-contingency situation.

The following contingencies were analyzed:

All facilities in the MPS system
All facilities in the EDE system
All facilities in the KCPL system
All facilities 115kV and above in the WR system
Relevant facilities in the AEC system
All facilities 115kV and above in the MEC system
All other facilities that are normally included in EDE contingency analysis studies

In total, 1406 contingencies were analyzed.

Percentage overloads as discussed in this report refer to the line's emergency rating.

III. EXISTING SYSTEM

A. System Configuration

The existing EDE transmission system (shown on the following page) has two 161kV lines and two 69kV lines that extend north towards the UCU system and provide possible interconnection points.

One possible interconnection location into the EDE system is at the Asbury Generation Station near Asbury, Missouri. There are three 161kV lines exiting this generating station. One line travels southwest to Carthage. Another line travels southwest to Joplin. The other 161kV line travels north to interconnect with the Western Resources system.

A second possible interconnection is location at the end of a 161kV line near Burns, Missouri. This substation is a 161/69kV substation fed from a radial 161kV line (795 ACSR) coming from Aurora. However, there are four 69kV lines exiting this substation that interconnect within the EDE system.

The last two possible interconnection points are normally open 69kV connections with MPS near Lamar (4/0 ACSR) and Warsaw (1/0 Cu). These interconnections are normally open because the Empire 69kV and the MPS are electrically out-of-phase by 30 degrees.

B. Loadflow and Contingency Analysis

The base case loadflow for the existing system (normal transfer scenario) is shown on page **Error! Bookmark not defined.**. The base case was based on a year 2003 Southwest Power Pool case with changes made to account for the addition of the Pleasant Hill plant and recommended transmission system changes due to the St. Joseph Light & Power merger. Nevada generation was off in the base case. Asbury generation was on in the base case and contributing 186 MW of generation.

The two most noticeable areas of concern regarding portions of the system that are impacted by this study are the Nevada area in the UCU system and the Burns area in the EDE system. Voltages in the Nevada area dropped as low as 87.7% (at Adrian) for outages on the 161kV line between Archie and Nevada. Voltages in the Burns area dropped as low as 87.7% an outage of the 161kV line to Burns.

C. Losses

Summer peak losses for the base case totaled 64.8 MW for the UCU and EDE systems.

IV. OPTION 1 - Nevada to Asbury 161kV Line

A. System Configuration

The first option considered for connecting the UCU and EDE electrical systems involved the construction of a 161kV line from near UCU's Nevada Substation to EDE's Asbury Generating Station (see diagram on the following page). This line was estimated to be 35 miles long and was modeled using 1192 ACSR conductor (312 MVA capability).

B. Estimated Cost

The estimated cost for this option is $14.84 million. The costs for this option are broken down as follows:

Construct a new 161kV Substation south of the existing Nevada Substation - $2.5 million
Add a 161kV breaker position at the existing Asbury Substation - $1.5 million
Construct a 161kV line (1192 ACSR) from the new Nevada Substation to Asbury - $10.84 million

Utilizing a levelized annual carrying charge of 15.4%, the cost of this option is $2.28 million annually and $7,300 / MW-year (for 312 MW of capacity).

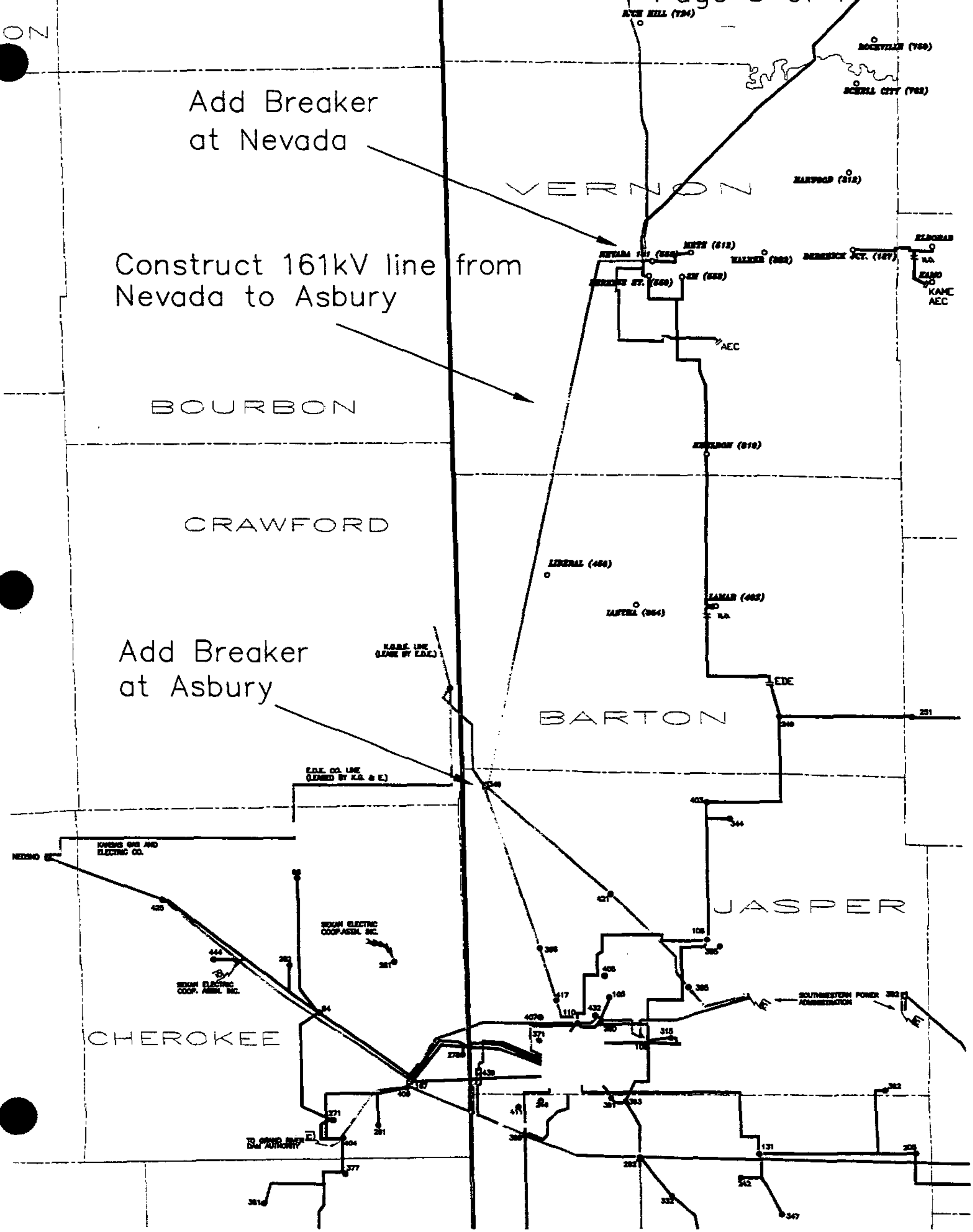
C. Loadflow and Contingency Analysis

The 2003 summer peak model showed 35.6 MW flowing from the Asbury Station to the Nevada Substation (see page **Error! Bookmark not defined.**). Flow from Archie Junction to the Nevada Substation was reduced by 14 MW. Voltages at the Nevada Substation improved from 97.3% to 99.2%.

The primary result of the addition of this line was the elimination of first contingency voltage problems in the Nevada area. In the base case, an outage of any section of the 49 mile line from Archie to Nevada at peak caused low voltages (as low as 87.7%) in the Nevada area. The addition of the line from Nevada to Asbury completely eliminated these single contingency voltage problems.

D. Losses

Losses for this option totaled 63.5 MW for the UCU and EDE systems. This is a peak reduction of 1.3 MW from the base case losses.


Add Breaker at Nevada
Construct 161kV line from Nevada to Asbury
Add Breaker at Asbury
VERNON
BOURBON
CRAWFORD
BARTON
JASPER
CHEROKEE
AEC
EDE
KAMO
AEC
KANSAS GAS AND ELECTRIC CO.
SEKAN ELECTRIC COOP. ASSN. INC.
SOUTHWESTERN POWER ADMINISTRATION

V. OPTION 2 - Sedalia to Burns 161kV Line

A. System Configuration

The second option considered for connecting the UCU and EDE electrical systems involved the construction of a 161kV line from UCU's Sedalia West Substation to EDE's Bolivar-Burns Substation (see diagram on the following page). This line was estimated to be 90 miles long and was modeled using 1192 ACSR conductor (312 MVA capability).

B. Estimated Cost

The estimated cost for this option is $30.87 million. The costs for this option are broken down as follows:

Upgrade to 161kV Substation at Bolivar-Burns Substation - $1.5 million
Add a 161kV breaker position at Sedealia West Substatoin - $1.5 million
Construct a 161kV line from Sedalia West to Bolivar-Burns Substation - $27.87 million

Utilizing a levelized annual carrying charge of 15.4%, the cost of this option is $4.75 million annually and $15,200 / MW-year (for 312 MW of capacity).

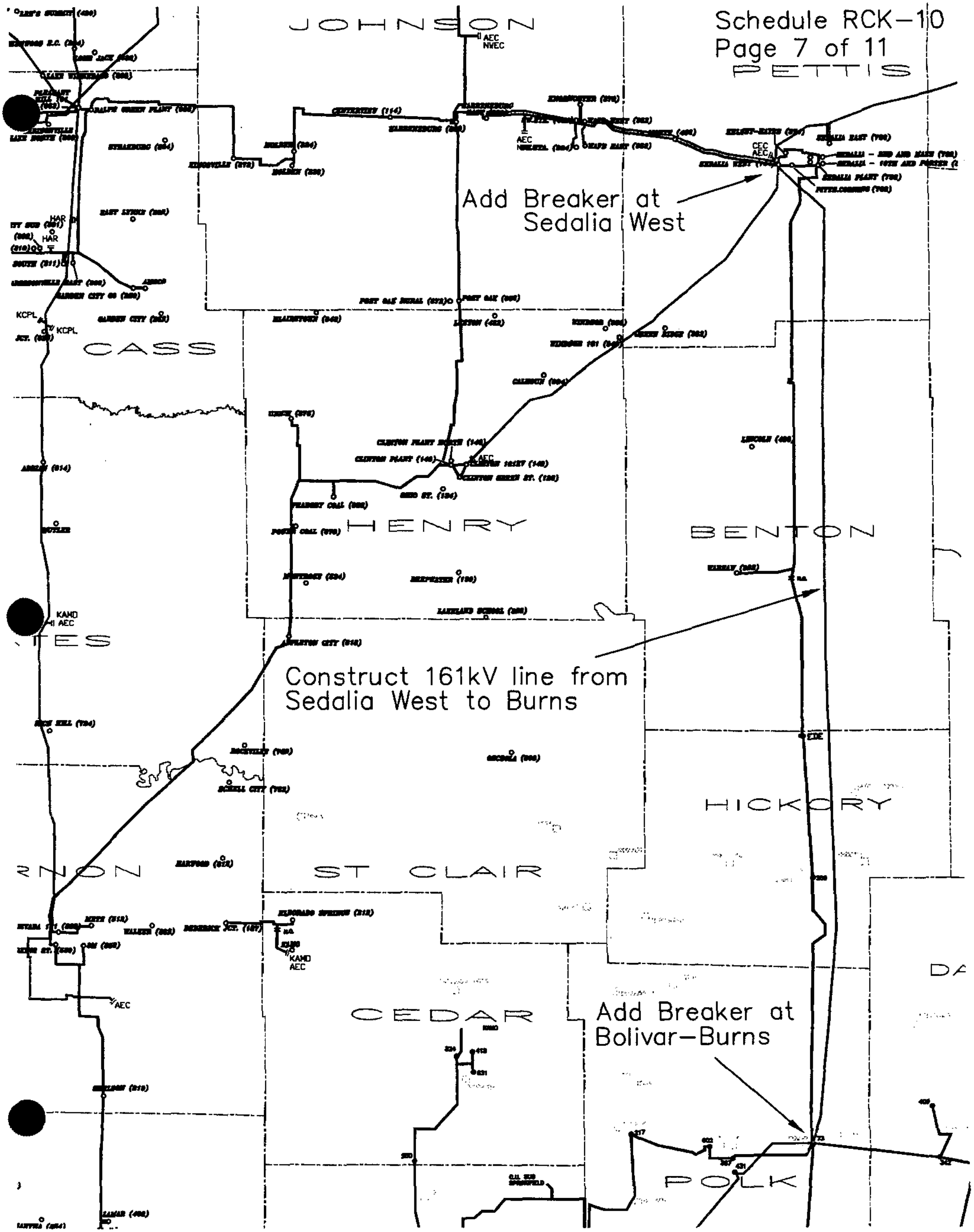
C. Loadflow and Contingency Analysis

The 2003 summer peak model showed 31.6 MW flowing from Sedalia West Substation to the Bolivar-Burns Substation (see page **Error! Bookmark not defined.**). The voltage in the Burns area improved from 97.7% to 99.1%.

The primary result of the addition of this line was the elimination of first contingency voltage problems in the Bolivar-Burns area. In the base case, an outage of any section of the 30 mile line Dadeville East Substation to the Bolivar-Burns Substation caused low voltages (as low as 87.7% at Bolivar South Substation). The addition of the line from Sedalia West to the Bolivar-Burns Substation completely eliminated these single contingency voltage problems.

D. Losses

Losses for this option totaled 65 MW for the UCU and EDE systems. This is an increase of 0.2 MW over the base case losses.


JOHNSON
PETTIS
CASS
HENRY
BENTON
ST CLAIR
HICKORY
CEDAR
POLK
AEC
NWEC
CEC
KCPL
HAR
KAMO
Add Breaker at
Sedalia West
Construct 161kV line from
Sedalia West to Burns
Add Breaker at
Bolivar–Burns

VI. OPTION 3 - Two 69kV Interconnections

A. System Configuration

The third option considered for connecting the UCU and EDE electrical systems involved the addition of two 69kV substations at existing 69kV interconnection points between the UCU and EDE transmission systems. Currently these 69kV interconnections are open because the UCU and EDE systems are 30 degrees out of phase. The new 69kV substations would include 69/69kV phase shifting transformers to bring the two systems into phase. One substation would be built at the 69kV interconnection near Warsaw and EDE's Hermitage Substation and one substation would be built at the 69kV interconnection near Lamar and EDE's Boston Substation (see diagram on the following page). The addition of both of these substations would add approximately 63 MW of interconnection capability at 69kV.

B. Estimated Cost

The estimated cost for this option is $3.5 million ($1.75 million for each substation).

Utilizing a levelized annual carrying charge of 15.4%, the cost of this option is $0.54 million annually and $8,600 / MW-year (for 63 MW of capacity).

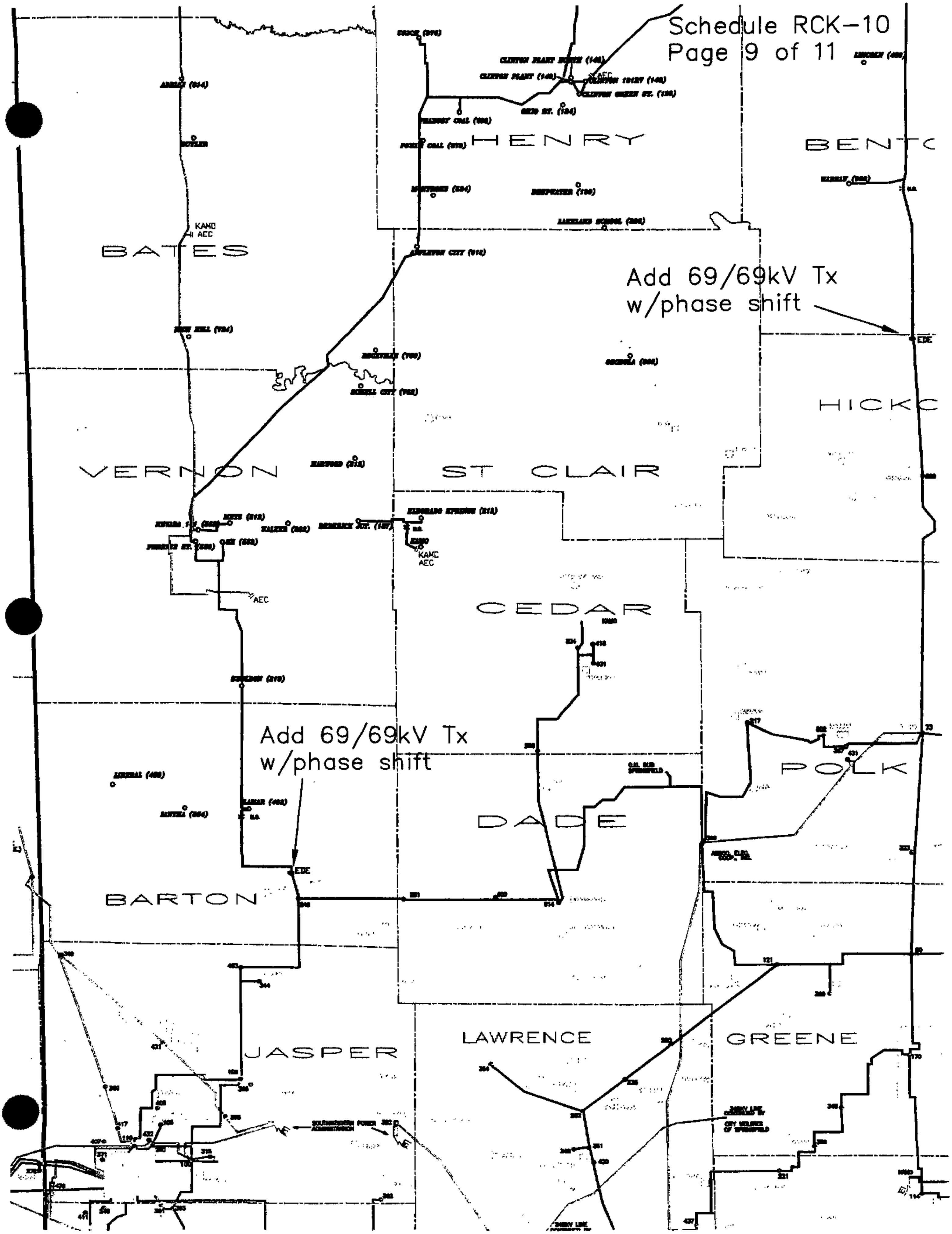
C. Loadflow and Contingency Analysis

The flow on the transformer near Lamar was 3.9 MW from Boston Substation (see page **Error! Bookmark not defined.**). The flow on the transfomer near Warsaw was 0.3 MW from Hermitage Substation. Voltage at Warsaw improved from 94.7% to 97%. Voltage at Lamar increased from 97.9% to 99.2%. Voltages in the EDE system decreased slightly.

This option provided backup to the Lamar area for outages on the 69kV line from Nevada to Lamar. It also provided off-peak backup to the Warsaw and Hermitage areas for outages of the 69kV radial lines serving those areas. Currently these areas have no second feed and are served radially.

D. Losses

Losses for this option totaled 64.7 MW, a decrease of 0.1 MW from the base case.


Add 69/69kV Tx
w/phase shift
EDE
Add 69/69kV Tx
w/phase shift
EDE
BATES
HENRY
VERNON
ST CLAIR
CEDAR
POLK
DADE
BARTON
JASPER
LAWRENCE
GREENE
BUTLER
KAMO
AEC
KAMO
AEC
AEC
AEC

VII. OPTION 4 - Purchasing Firm Transmission

A. System Configuration

This option involves no changes to the existing transmission system. Necessary transmission capacity would be purchased (from either KCPL or Western Resources).

B. Estimated Cost

It is estimated that 300 MW of transmission capacity is necessary to operate the two systems as one control area and to be able to perform economic dispatch between both systems.

KCPL's current annual revenue requirement for network service is $42,101,320 (includes the Scheduling & Dispatching charge) plus payment for energy losses. If the KCPL system load is estimated at 3,402 MW (2003 summer load), then the load ratio share of 300 MW of transmission capacity is

300 / 3,402 X $42,101,320 = $3.7 million annually (plus energy losses).

The calculation for Western Resources is

300 / 5,400 (estimated 2003 summer peak) X $66,491,775 (annual revenue requirement)
= $3.7 million annually.

The cost for this option is roughly $3.7 million annually or $12,300 / MW-year (300 MW capacity).

C. Loadflow and Contingency Analysis

Because this option does not require any changes to the existing system, the transmission system is unaffected compared to the base case.

D. Losses

Because this option does not require any changes to the existing system, losses for this option are equivalent to the base case.

VIII. SUMMARY

A. Comparing the Options

Determining the preferred method of connecting the UCU and EDE transmission systems from the four options considered in this report is a simple matter given the estimated costs and benefits of each option. Of the four options, Option 1 (Nevada - Asbury) has the lowest costs (see summary of costs on page 13) and provides a benefit to the transmission system. Option 2 (Sedalia - Burns) also provides roughly equivalent benefits to the transmission system, but has substantially higher costs. Option 3 does provide some benefits to the transmission system, but does not provide the necessary 300 MW of interconnection capability that is considered necessary between the two systems. It also has a higher cost on a $ per MW-Year basis than Option 1. Option 4 (buying transmission capacity) provides no benefits to the transmission system and has substantially higher costs than Option 1.

B. Recommendation

The recommended course of action is to construct a 161kV line from a location south of the existing UCU Nevada Substation to the EDE Asbury generating station (see diagram on page 5).

C. Additional Considerations of the Preferred Option

There are least two modifications that can be made to the preferred option that need to be considered.

1. Increasing the Capacity of the Conductor - Replacing the proposed 1192 ACSR conductor with 795 bundled ACSR conductor will increase the capacity of the line from 312 MVA to 510 MVA. If at some point in the future a greater amount of capacity between the two systems is required, it will be more expensive on a $/MW-Year basis to increase the capacity beyond the 312 MVA given by the 1192 ACSR. Additional capacity could be added in the future by completing the 69kV interconnections as described in Option 3 (63 MW) or by purchasing firm capacity as described in Option 4. The difference in costs between these two conductor types is still being evaluated.

   Flow on the Nevada - Asbury line increases by approximately 14% at peak when 795 bundled ACSR conductor is used (as opposed to the 1192 ACSR conductor).

2. Terminating the Connection at Nevada Substation Instead of Further South - Another possibility for this line would have the line terminating at Nevada Substation (see diagram on page 12), instead of further south (as shown on page 5). Originally, the Nevada - Asbury line was considered from the southern location, because it is approximately 7 miles closer to Asbury. Terminating this line at the existing Nevada Substation would add 7 miles of 161kV construction to the cost. However, costs would also be reduced by not requiring the construction of a new 161kV substation. An additional breaker position would be needed at the existing Nevada Substation, if it is decided to terminate the line there. The difference in costs between these two options is still being evaluated.

   If the line is terminated at the existing Nevada Substation, the reliability to Nevada increases slightly. The existing substation would then have three 161kV lines exiting the station and would eliminate the possibility of a radial feed to the substation due to a single 161kV line outage.

Initial Comments of
UtiliCorp United, Inc.
filed in response
to the Federal Energy Regulatory Commission
Notice of Proposed Rulemaking Regarding
Regional Transmission Organizations

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Notice of Proposed Rulemaking	)	
Regarding Regional	)	Docket No. RM99-2-000
Transmission Organizations	)	

INITIAL COMMENTS OF UTILICORP UNITED, INC.

In response to the above-captioned Notice of Proposed Rulemaking, UtiliCorp United Inc. ("UtiliCorp") is pleased to submit its Initial Comments.

As the Federal Energy Regulatory Commission ("Commission") itself has pointed out in the NOPR, "Competition in wholesale electricity markets is the best way to protect the public interest and insure that electricity consumers pay the lowest price possible for reliable service." (NOPR at 6). The Commission also states, and UtiliCorp agrees, that regional approaches are necessary in order to move toward the elimination of continuing impediments to competitive electricity markets in the United States. The Commission has stated as its objective in that regard that all transmission entities in the nation, including non-jurisdictional entities, should place their transmission facilities under the control of appropriate regional transmission institutions in a timely manner. UtiliCorp supports this objective and offers the following specific comments for the Commission's consideration.

UtiliCorp's Role in the Energy Industry

Because of the diverse nature of UtiliCorp's energy business, which encompasses natural gas and electricity, and traditional regulated utility and competitive energy marketing operations, UtiliCorp believes that it is in a position to provide a balanced perspective to the Commission regarding the competitive market issues implicated by the NOPR. On the regulated side of its business, UtiliCorp provides electric service to retail and wholesale customers in the States of Missouri, Kansas, Colorado and West Virginia, and also owns natural gas utilities in eight states. As an owner of electric transmission facilities, UtiliCorp will be directly affected by the requirements imposed on such owners by the final rule adopted in the current proceeding.

Moreover, UtiliCorp has been a leading player in the market for competitive sales of energy, including sales of both electricity and natural gas. Its power marketing subsidiary, Aquila Energy Marketing Corporation ("AEMC"), purchases and sells electric power in virtually every region of the country and is currently ranked number two in overall energy sales. In its Merchant Energy Partners entity, UtiliCorp owns interests in sixteen independent and qualifying generation facilities in six states. In its capacity as a leading power marketer and owner and operator of generation in other markets, UtiliCorp will thus be directly affected by the final rule adopted herein, and the potential new market opportunities that will be created as a result of the further reduction of structural impediments to competition.

Finally, UtiliCorp also has significant ownership interests in utility operations in Australia, New Zealand, and the United Kingdom,1/ each of which are well down the road to restructuring their electric utility industries in order to gain the benefits of competitive markets in the generation sector. The experience UtiliCorp has gained as a result of its business operations in those ground-breaking jurisdictions places the Company in a uniquely advantageous position from which to comment knowledgeably on the matters at issue in this proceeding.

UtiliCorp's Long-Standing Support for the RTO Concept

UtiliCorp first "went on record" with its position in favor of action by this Commission to promote regional transmission organizations in its comments in response to the March 29, 1995 Notice of Proposed Rulemaking on Open-Access Transmission. 2/ In those comments four years ago, UtiliCorp anticipated developments that have occurred in the industry since that time, in the form of proposals for independent system operators and privately owned transmission entities. Further developments of this kind are now in position to be accelerated significantly by a final rule in this proceeding. We take this opportunity to salute the Commission in issuing the current NOPR, both for its initiative in requiring

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1/ UtiliCorp also owns interests in utility or generation operations in Western Canada and in Jamaica.

2/ Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Standed Costs by Public Utilities and Transmitting Utilities, Docket No. RM95-8-000 et al.

jurisdictional utilities to confront the issue of forming or joining an RTO and for its forbearance in declining to propose overly prescriptive mandates regarding the implementation issues, which often involve complex business and legal considerations among the parties affected. Nevertheless, the Commission in the NOPR has been clear as to the basic principles that it will apply in promoting the creation and approving the establishment of RTOs. The balance struck by the Commission is a good one and is worthy of praise.

The primary motivating force behind the initiation of this rulemaking is, quite properly, the Commission's recognition in the NOPR that under present industry conditions, there is not fair and open access to transmission for those who wish to compete with the large transmission-owning utilities for wholesale customers. In its business operations as a power marketer in numerous regional markets, UtiliCorp has experienced such discriminatory behavior directly and significantly, one instance of which the Commission has specifically acknowledged at page 71 of the NOPR. 3/ By removing control over access to transmission from the remaining large transmission owning utilities, and placing such control in properly structured regional transmission organizations, the Commission will go a

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3/ The NOPR cites the case of Aquila Power Corporation v. Entergy Services, Inc., Docket No. EL98-36-30, Amended and Restated Complaint at 6 (filed June 23, 1998).

long way toward eliminating the remaining obstructions to effective competition in wholesale markets for electric power. 4/

The Commission's Proposed Minimum
Characteristics and Functions of an "RTO"

In its decision to refrain from issuing a mandate to jurisdictional utilities to form or join an RTO, the Commission has proposed an alternative approach based on the adoption of incentives for the creation of RTOs that have certain minimum characteristics and perform certain minimum functions. Such preferred, qualifying "RTOs", according to the NOPR, may be entitled to certain regulatory benefits under consideration by the Commission, including more favorable rates of return on equity, possible incentive pricing opportunities, expedited approvals, and other forms of preferential treatment not accorded to proposed transmission entities that do not possess such features. Such an approach has much to commend it, but places a daunting responsibility on the Commission to get both the minimum characteristics and the incentives right. In its comments herein, UtiliCorp wishes to focus attention on those aspects of the NOPR that UtiliCorp considers most determinative of the likely success or failure of a final rule adopted in this proceeding. Our comments are presented in the order in which the

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4/ We note as a caveat, however, that such action cannot be completely effective unless the Commission also strengthens and enforces its policies and precedent prohibiting utility discrimination against wholesale users of transmission in favor of their own uses of transmission for native load. See Amended and Restated Complaint cited in footnote 3, supra, and authorities cited therein.

Commission has addressed the RTO characteristics and functions and other issues in the NOPR.

The Characteristics of an RTO

(a) Independence - It comes as no surprise that "independence" is established as the Commission's number one criterion for a qualifying RTO. In the NOPR, the Commission reaffirms its earlier statement, made in the context of ISOs, that "the principle of independence is the bedrock on which the [RTO] must be built." (NOPR at 119). It states that this criterion can be achieved if three conditions are satisfied: first, that the RTO, its non-stakeholder governing board, and its employees must have no financial interests in market participants; second, that its decision making must not be "controlled" by any market participants; and third, that it must have complete authority to file changes to its transmission tariff.

Subject to the provisos noted below, UtiliCorp supports the concept that the governing board of an RTO should not include members having a financial interest in any market participant and that similar prohibitions should apply to the employees of an RTO. 5/ The first proviso is that the *decisional* structure of an RTO should incorporate an entity or other formal mechanism providing for stakeholder input to the non-stakeholder board. Such input would not bind the independent board, but would operate to make sure that the views of stakeholders are

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5/ Exception should be made for the pension rights of former utility employees who become employees of an RTO. Otherwise, RTOs could face significant difficulties in hiring qualified and experienced transmission personnel.

considered. The stakeholder entity should be broadly inclusive of all market participants having a (defined) threshold economic interest in the RTO's policies and actions.

The second proviso concerns the *ownership* structure of an RTO. In its discussion of this matter in the NOPR, it appears that the Commission has, perhaps inadvertently, unduly restricted the ability of market participants to have an ownership interest in an RTO, as distinct from a role in its decision making. In that regard, UtiliCorp believes that the proposed one-percent ownership limitation mentioned in the NOPR is unduly restrictive and may potentially choke off significant sources of capital needed for the formation of the kind of entity that the Commission seeks to encourage.

This concern becomes self-evident when the concept of the for-profit, transco-type RTO ("Transco") is considered. If Commission policy is intended to encourage the transfer of control over assets to properly structured Transco entities, sufficient latitude must be provided for recognition of the value of such contributions. Given the start-up difficulties in raising money for newly created entities of this kind, an RTO is not likely to have access to cash resources sufficient to purchase the assets it will require. It will thus be necessary in most instances to permit transfers of assets in return for ownership interests in the RTO. With the use of certain kinds of business organizations (e.g., partnerships and limited liability corporations), control of the enterprise for decision-making can be separated from ownership of the assets. Parties should be permitted considerable business latitude to attempt to work out such arrangements, subject to the caveat that the resulting distribution of ownership interests leave no owner in a position of undue influence or, worse, de facto control. The caveat would generally be satisfied in situations where the RTO is of sufficient geographical size and scope such that any individual owner's percentage share, in the context of the overall distribution of other ownership interests, would be significantly diluted to the point that it could not reasonably be suggestive of undue influence on or *de facto* control of an independent board. 6/ UtiliCorp submits that this judgment should be made on a case-by-case basis, considering all relevant facts, and that adoption of an arbitrary percentage limitation on ownership of an RTO by an individual participant should be avoided.

The concerns described may not arise to the same extent in the context of RTOs that are organized as non-profit Independent System Operators ("ISOs"); however, UtiliCorp submits that it would be a mistake for the Commission to adopt policies that favor RTOs organized in the form of ISOs and that discourage the formation of properly structured, for-profit "Transcos". In the past, UtiliCorp has advocated large, for-profit transmission entities, regulated by this Commission, as the best long-term business model for regional transmission organizations. We continue in that belief: entities that are properly organized and incented to

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6/ By contrast, the Transco proposed by Entergy in Docket No. EL 99-57 would not pass muster under the approach described, unless it were joined by a sufficiently large number of other transmission-owning utilities to dilute Entergy's currently exclusive ownership interest to a satisfactory extent.

maximize the value of transmission assets as a stand-alone business are most likely to be accountable to their shareholders, to their customers and to this Commission. At the same time, we realize that intermediate stages of development of RTOs may be required in the ultimate progression to the establishment of such entities on the largest scale. In that evolution, the formation of ISOs may be a necessary interim step in some circumstances. 7/ However, we submit that the ultimate objective should be the establishment of privately-owned, regulated transmission entities, which are subject to the discipline of the marketplace, possessed of the proper incentives for efficient performance, and empowered to make investments pursuant to long-term plans properly vetted before regulators and affected parties.

We note, in that regard, that the Commission should take steps in any final rule issued in this proceeding to ensure that the next stage of implementation of RTOs does not become the last. The danger in recognizing the potential need for intermediate stages in the development of RTOs is that, having once been formed, such interim entities may become subject to the inertia and resistance to change that is often characteristic of large, bureaucratic institutions. Those tendencies can be especially pronounced in entities that are structured to accommodate the direct participation of a variety of conflicting interests in the RTO's decision-making process. The result of a proliferation of such entities after issuance of a final rule

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7/ An example of such circumstances would be a situation where the participation by non-jurisdictional utilities in an RTO is deemed beneficial or essential, but could not be accommodated within the legal framework of a for-profit Transco RTO.

herein could be a freeze on further evolution and a semi-permanent balkanization of the grid. We suggest that the Commission, in its final order, should adopt a specific schedule for future reporting and evaluation of all RTOs proposed as a result of this rulemaking and should make it clear that continuing improvement, consolidation and enlargement of RTOs are expected and, if necessary, will be required.

(b) Appropriate Scope and Regional Configuration. UtiliCorp's public position on this issue has been that RTOs should be as large as practicable, subject only to the physical constraints within and between the existing major Interconnections in the U.S. As we read the NOPR, the Commission has endorsed that principle; however, UtiliCorp believes the Commission is also correct in its decision not to propose regional RTO boundaries on its own. Instead, the Commission has identified certain "relevant factors" in the NOPR that it will use when evaluating the boundaries of a proposed RTO, including whether such boundaries (a) allow the RTO to perform its essential functions, (b) support trading over a large area, (c) thwart the exercise of market power, (d) encompass existing control areas, regional transmission entities, a contiguous geographic area, and "a highly interconnected portion of the grid" and (e) take into account existing regional and international boundaries. Those factors seem to us to be appropriate. 8/

8/ UtiliCorp notes again here its belief in the importance of the RTO's ability to thwart market power, especially in the context of eliminating participating utilities' capabilities and incentives to obtain undue preferences for transmission used to serve native load.

In its 1995 comments, UtiliCorp suggested that a Commission-approved RTO should be no smaller than the NERC Reliability Council in which it was located. It is apparent from recent industry developments and discussions that RTOs are being considered for regions that extend well beyond the boundaries of the individual NERC reliability regions.

As a national energy trading company, UtiliCorp starts from the position that the configurations of RTOs should, at a minimum, reflect the actual trading patterns in the principal power marketing areas of the United States. Using that frame of reference, the Western Interconnection could all be included in a single RTO (subject to caveats regarding the need for continuing to recognize separate control areas, discussed further below). For obvious reasons, ERCOT would continue as a separate system, and a Florida RTO would probably make sense (at least initially), given its relative isolation from the other transmission systems in the Southeast. 9/ Leaving aside the existing ISOs in New England, New York, PJM and the Midwest, which will be the subject of subsequent inquiry by the Commission, 10/ the remaining NERC regions in the Eastern Interconnection present some interesting potential RTO configurations. Regarding MAPP, SPP, ECAR, SERC and MAIN, various combinations of transmission systems are under

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9/ We note, however, that to the extent that the Commission authorizes multiple RTOs within the Eastern Interconnection, it should require such RTOs to develop pricing mechanisms and operating policies that make transmission service across such RTOs as seamless as reasonably possible.

10/ See NOPR at 208-209.

active consideration and may be proposed as RTOs. UtiliCorp does not wish to anticipate or prejudge the results of those discussions with its comments herein. With respect to MAPP and SPP, in particular, UtiliCorp will be facing its own business decision as to which of several RTO entities currently under discussion makes the most sense for its energy customers, utility ratepayers and shareholders. UtiliCorp commends the Commission for its willingness to permit the affected participants to agree on the appropriate scope of RTOs in this region, at least in the first instance.

(c) Operational Authority Over all Transmission Facilities. UtiliCorp supports the Commission's determination in the NOPR that an RTO meeting its requirements must have "operational control" of the transmission facilities under its control (NOPR at 140). This characteristic is, without question, an essential one. In exercising such control, the NOPR states that the RTO "may choose to directly operate facilities . . ., delegate certain tasks to other entities . . . or use a combination of the two approaches." Such practical flexibility is also desirable. We support the proposition that the RTO is not necessarily required to operate a single control area, which is a particularly important factor in the Midwest. However, UtiliCorp strongly endorses the Commission's statement that the RTO "must have ultimate responsibility for providing non-discriminatory transmission service for all market participants and for ensuring the short-term reliability of the grid." (NOPR at 142).

Finally, we strongly support the Commission's position that the RTO must be the security coordinator for the transmission facilities that it controls, for the following reasons: (1) there will otherwise be competing entities responsible for reliability functions within the RTO area, and (2) an independent RTO will thus not be able to achieve the Commission's objectives of independent management of the transmission network if ultimate control remains in the hands of security centers controlled by a few (and in some cases, one) market participants.

At present, there are twenty-three security centers in NERC, five of which are in SERC. Aquila Energy's experience with Entergy leads us to conclude that the security function should be managed by entities that are independent of market participants. If RTOs are designated to be those independent entities, the security center functions should be transferred to the RTO.

There is also the potential for overlap between RTOs and NERC reliability councils, because RTOs that cross reliability council boundaries may perform their reliability-related functions differently than the local reliability councils perform them. Unless NERC reliability councils become RTOs themselves (which is under active discussion in certain regions), there will need to be a clear demarcation of responsibilities assigned to RTOs and the regional reliability councils.

(d) Exclusive Authority to Maintain Short-Term Reliability. The Commission proposes in the NOPR that an RTO must be responsible for maintaining short-term reliability and therefore should have the authority to review and implement interchange schedules, order generation dispatch, authorize scheduled maintenance outages of transmission facilities, monitor equipment availability and loading and establish facility ratings. Regarding the matter of generation dispatch, UtiliCorp concurs with the Commission's statement that an RTO "must have some degree of control over some generation," but that control should not necessarily extend to initial unit commitment or central dispatch (NOPR at 148). In the Midwest, where there is no structure for central dispatch across utility boundaries, it would be counterproductive to require such authority or capability of an RTO. UtiliCorp believes that it is fully sufficient, for purposes of the objectives sought by the NOPR, that an RTO have the ability to redispatch generation for reliability and for handling transactions between control areas.

Minimum Functions of an RTO

The Commission has identified seven functions in the NOPR as the minimum functions that an RTO must perform. They are discussed, in turn, as follows:

(1) *The RTO must administer its own tariff and employ a pricing system that will promote efficient use and expansion of transmission and generation facilities.* UtiliCorp endorses this minimum RTO function. Specifically, we support the proposed requirements that the RTO must be the sole provider of service over the facilities it controls and the sole administrator of its open-access tariff, that the RTO must have sole authority to act on requests for transmission service and new interconnections, and that the RTO must ensure non-pancaked transmission rates.

These requirements are fundamental to the concept and purpose of any regional transmission entity. UtiliCorp also believes that it is important that an RTO tariff cover all transmission facilities within the RTO's region of operation (in contrast to the situation in NEPOOL where a transmission customer must obtain service from the NEPOOL ISO for the use of pool facilities and from individual transmission providers for the use of non-pool facilities).

(2) The RTO must create market mechanisms to manage transmission congestion. UtiliCorp supports this proposed function as well and specifically concurs with the Commission's further comments that a congestion management system should establish tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and give market participants the opportunity to hedge locational differences in energy prices. We also concur with the Commission's stated objectives regarding congestion management -- i.e., that the generators dispatched in the presence of transmission constraints should be the least-cost units able to serve load (given the constraints) and that limited transmission capacity should be used by market participants that value such use most highly. (The effective ceiling on the value of such use would be the differential cost of the generation on the other side of the constraint.)

(3) The RTO should develop and implement procedures to address parallel path flow issues within its region and within other regions. In UtiliCorp's experience, this is one of the most important problems facing adjoining regions

today and may be a significant contributing factor to the problems of line loading relief and congestion. The Commission has proposed in the NOPR that RTOs be required to address parallel path flow issues between regions within three years. In UtiliCorp's view, a three-year time frame seems reasonable for full implementation, and not simply for filing a plan to seek approval. UtiliCorp believes the Commission would be on sound ground to require that RTOs be required to file their plan within one year and have it fully operational within two years thereafter, if not sooner.

(4) The RTO must serve as a supplier of last resort for ancillary services required in Order No. 888. UtiliCorp supports this requirement and endorses the further point that the RTO must ensure public access to real-time balancing information.

(5) The RTO must operate a single OASIS site for all transmission facilities under its control and must have exclusive responsibility for determining Available Transmission Capability ("ATC"). This proposed requirement for an RTO is, in our view, absolutely essential. In this connection, UtiliCorp strongly supports the Commission's observation in the NOPR that "there is widespread dissatisfaction with the reliability of posted ATC numbers." Specifically, UtiliCorp is one of those which the NOPR identifies as having alleged "that transmission providers who also compete in power markets against their competitors have both the incentive and ability to post unreliable ATC numbers." We submit that the same thing is true in the case of Capacity Benefit Margin ("CBM") calculations. This issue is at the core

of the discriminatory behavior UtiliCorp and other power marketers have experienced at the hands of certain large transmission-owning utilities, which have appeared to use ATC and CBM calculations in attempts to shield their high-cost generation from effective competition. Where the RTO is not itself the control area operator, the RTO must have the ability and the authority to determine independently the control area operator's transmission needs as they affect ATC and CBM calculations.

(6) The RTO is required to monitor markets to identify problems, measure market power, and propose appropriate remedies. Regarding this proposed function for RTOs, UtiliCorp departs somewhat from its generally supportive comments on other issues and suggests that caution is in order here. It is not at all clear to us why a market monitoring function should be viewed as essential or even appropriate for an RTO, especially since the Commission itself will continue to have market oversight responsibilities, including the continuing judicial function and responsibility to entertain complaints alleging discriminatory behavior. For one thing, there is a material difference between a technical organization, such as an ISO, that is responsible for transmission network management and associated reliability functions, and a commercial entity focused on pricing and market issues. The skill sets are different, and UtiliCorp has experienced this difference firsthand in analogous power pool situations. On the other hand, assignment of market-monitoring functions to a commercial entity, such as a Transco (other than those functions concerned strictly with transmission pricing) may raise other problems,

including antitrust concerns, both for the Transco and its customers. We submit that the Commission should be very circumspect in any delegation of such functions to an independent transmission organization, regardless of whether such entity is organized as a non-profit or as a privately owned transmission provider.

(7) The RTO should plan and facilitate necessary transmission additions and upgrades and is responsible for coordinating such efforts with state regulators. As to this function, UtiliCorp notes especially the Commission's further comment that the planning and expansion process must encourage market-driven operations and investments for preventing and relieving congestion. As we pointed out above, UtiliCorp believes that the best guarantee that such investment will occur is, ultimately, the creation of properly structured region-wide "Transcos." One of the most frequently heard industry complaints about ISOs is the absence of economic incentives for ISOs to make the investments required to increase transmission capacity and improve efficiency. Because of the uncertainties attendant to the varied approaches to the restructuring of electric utilities by the state authorities, many needed investments in transmission have been postponed by the transmission-owning utilities, or canceled altogether. It is incumbent on this Commission, in its final rule, to ensure that it creates the proper incentives to encourage such investment and, at a minimum, that it take no action having the effect of imposing further delay of such investments.

<u>Incentives for the Formation of RTOs</u>

The most important, and arguably the most innovative, tool proposed by the Commission for the encouragement of the formation of RTOs is found at pages 199-200 of the NOPR, where the Commission states, "We would be willing to consider, on a case-by-case basis, allowing the transmission owners that bring about [RTO] benefits to share in them through incentive pricing for public utility transmission owners that turn over control of their transmission facilities to an RTO." UtiliCorp views this pronouncement by the Commission as a significant policy departure, and we commend it for expressing an open mindedness to this concept. Initially, UtiliCorp notes that there are two distinct types of incentives that the Commission needs to consider in the context of a final rule: first, incentives for transmission-owning utilities to form or join RTOs, and second, incentives for RTOs to perform at optimum efficiency after they are formed.

Given the Commission's decision in the NOPR to encourage, but not require, jurisdictional utilities to join RTOs, the issue of what incentives to adopt is necessarily a critical consideration. One of the basic challenges facing the Commission in this regard is the fact that for many large, transmission-owning utilities, state regulatory authorities effectively determine the rate of return on equity on all but a relatively small percentage of their transmission assets. For utilities that enjoy higher state-allowed rates of return on equity than those permitted under the policy and precedent of this Commission, there will naturally be resistance to any substantial revenue reductions occasioned by the transfer of such assets to an RTO that is regulated under the traditional rate-making policies of this Commission. In the situations described, the crux of the problem is to remove disincentives to the formation of RTOs.

When seen in this context, UtiliCorp submits that the proper metaphor for "incentive" returns on equity is "basic sustenance", rather than regulatory "candy", as some have suggested. Unless and until the Commission decides to take mandatory action forcing jurisdictional utilities to join RTOs, it will have no choice but to entertain proposals for higher permitted returns on equity than it has traditionally allowed, assuming utilization of a standard cost-of-service approach for the pricing of transmission services by an RTO. In entertaining such proposals, however, the Commission should -- indeed, is required to -- scrutinize carefully the asserted bases for the returns requested. As both an owner of transmission assets in its own territory and a user of transmission services in other parts of the country, UtiliCorp has revenue concerns on both sides of this issue and believes that the proper balance will have to be determined by the Commission on a case-by-case basis.

Another incentive option mentioned by the Commission in the NOPR is a rate-making approach in which transmission rates would be allowed to be kept at current levels (or levels to be determined upon formation of the RTO) for a defined period of time, even though RTOs are expected to achieve cost savings in their operations, as compared to current levels. Based on the experience of several foreign jurisdictions that have tried this approach, it can produce significant benefits, although the determination of the proper fixed rates on the front end will obviously be an important action, of interest to all affected parties. Certainly, it is helpful that the Commission has shown itself open to the receipt of such proposals. The essential first step is that such proposals be elicited in the first instance, after which the appropriate scrutiny can be applied.

Finally, the Commission has also shown itself open to the consideration of allowing accelerated cost recovery for new facilities constructed, owned and operated by RTOs meeting the Commission's criteria. UtiliCorp supports this concept, especially in view of the urgent need for new investment in the transmission grid in this country. We do not read the NOPR to suggest, and would not support, the elimination of regulatory oversight with respect to such proposals. The details will be important, and all affected parties -- owners and transmission customers alike -- should have a say in these matters, in the traditional regulatory context.

The Power Exchange Issue

Finally, UtiliCorp wishes to go on record as supporting the Commission's proposal to allow each region to decide whether a power exchange should be established and whether the RTO should also operate the power exchange. UtiliCorp is generally opposed to the mandatory power exchange model and notes that certain foreign jurisdictions (e.g., the UK) which had previously adopted that model are now moving to a more open approach. In any event, we believe that the complex and controversial issues connected with the establishment of a mandatory power exchange should not be folded into a proceeding such as this one, in which the focus is properly on the establishment of Regional Transmission Organizations to reduce or eliminate the remaining barriers to access to transmission on equal and nondiscriminatory terms.