98. DE, DC, NJ and MD Coms	Delaware Public Service Commission, District of Columbia Public Service Commission, Maryland Public Service Commission, and New Jersey Board of Public Utilities.
99. Deloitte & Touche	Deloitte & Touche LLP.
100. Destec	Destec Energy.
101. Detroit Edison	Detroit Edison Company.
102. Detroit Edison	Detroit Edison Wholesale Customers (consisting of City of Croswell, Michigan, and Thumb Electric Cooperative).
103. Direct Service Industries	Direct Service Industries (consisting of ELF Atochem North America, Inc., Columbia Columbia Aluminum Corporation, Columbia Falls Aluminum Co., Georgia Pacific, Kaiser Aluminum & Chemical Corporation, Intalco Aluminum, Northwest Aluminum Company, Reynolds Metals Company and Vanalco, Inc.).
104. DOD	Department of Defense.
105. DOE	United States Department of Energy.
106. DOJ	United States Department of Justice.
107. Dominion	Dominion Resources.
108. Douglas EC	Douglas Electric Cooperative, Inc.
109. Duke	Duke Power Company.
110. Duquesne	Duquesne Light Company.
111. East Kentucky	East Kentucky Power Cooperative, Big Rivers Electric Corporation, and Hoosier Energy Rural Electric Cooperative.
112. East River EC	East River Electric Power Cooperative.
113. EDS Utilities	Electronic Data Systems Inc., Utilities Division (Joussef Heguzy, Clifford J. Meagh, Julius A. Wright).
114. Education	American Council on Education and the National Association of College and University Business Officers
115.	EEI Edison Electric Institute.
116. EGA	Electric Generation Association.
117. El Paso	El Paso Electric Company.
118. ELCON	Electricity Consumers Resource Council, American Iron and Steel Institute, Chemical Manufacturers Association and Council of Industrial Boiler Owners.
119. Electric Consumers Alliance	Electric Consumers' Alliance.

120. Electronic Data Systems	EDS Utilities Division (James F. Susman).
121. ENEREX	ENEREX, Inc.
122. Entergy	Entergy Services, Inc.
123. Entergy Retail Regulators	Arkansas Public Service Commission, City Council of New Orleans, Louisiana Public Service Commission, and Mississippi Public Service Commission.
124. Environmental Action	Environmental Action Foundation.
125. EPA	United States Environmental Protection Agency.
126. Fertilizer Institute	The Fertilizer Institute.
127. FL Com	Florida Public Service Commission.
128. Florida Power Corp	Florida Power Corporation.
129. FPL	Florida Power & Light Company.
130. Freedom Energy Co	Freedom Energy Company, LLC.
131. FTC	United States Federal Trade Commission, Staff of the Bureau of Economics.
132. Fuel Managers	Fuel Managers Association.
133. GA Com	Georgia Public Service Commission.
134. GAPP Committee	General Agreement of Parallel Paths Committee (A. Garfield).
135. Graves	Graves, Frank and Ilic, Marija.
136. Green Mountain	Green Mountain Power Corporation.
137. Heartland	Heartland Consumers Power District.
138. Hogan	Hogan, William W.
139. Home Builders	National Association of Home Builders.
140. Homelessness Alliance	National Alliance to End Homelessness, Inc.
141. Hoosier EC	Hoosier Energy Rural Electric Cooperative.
142. Hopkinsville EC	Hopkinsville Electric System.
143. Houston L&P	Houston Lighting & Power Company.
144. Hydro-Quebec	Hydro-Quebec.
145. IA Com	Iowa Utilities Board.
146. IBM	International Business Machines.

147. ID Com	Idaho Public Utilities Commission.
148. Ida County REC	Ida County Rural Electric Cooperative.
149. Idaho	Idaho Power Company.
150. IES Utilities	IES Utilities Inc.
151. IL Com	Illinois Commerce Commission.
152. IL Industrials	Illinois Industrial Energy Consumers.
153. Illinois Municipal Electric Agency	Illinois Municipal Electric Agency.
154. Illinois Power	Illinois Power Company.
155. IN Com	Indiana Utility Regulatory Commission.
156. IN Industrials	Indiana Industrial Energy Consumers, Inc.
157. Industrial Energy Applications	Industrial Energy Applications.
158. Inland Power Pool	Inland Power Pool.
159. IPALCO	IPALCO Enterprises, Inc.
160. James Valley EC	James Valley Electric Cooperative, Inc.
161. Jay	Town of Jay, Maine and the Jay Power District.
162. KCPL	Kansas City Power & Light Company.
163. Knoxville	Knoxville Utilities Board.
164. KS Com	Kansas Corporation Commission Staff.
165. KU	Kentucky Utilities Company.
166. KY AG	Kentucky Attorney General.
167. KY Com	Kentucky Public Service Commission.
168. LA DWP	Department of Water and Power of the City of Los Angeles.
169. LA Industrials	Louisiana Energy Users Group.
170. La Raza	National Council of La Raza.
171. Las Cruces	City of Las Cruces, New Mexico.
172. Latin League	League of United Latin American Citizens.
173. Legal Environmental Assistance	Legal Environmental Assistance Foundation.
174. LEPA	Louisiana Energy and Power Authority.
175. Lester Fink	Fink, Lester.

176. LG&E	LG&E Energy Corp.
177. LILCO	Long Island Lighting Company.
178. Lincoln-Union EC	Lincoln-Union Electric Company.
179. Lively	Lively, Mark B.
180. Local Furnishing Utilities	Local Furnishing Utilities (Long Island Lighting Company, Nevada Power Company, and San Diego Gas & Electric Company).
181. Lower Colorado River Authority	Lower Colorado River Authority.
182. LPPC	Large Public Power Council.
183. MA DPU	Massachusetts Department of Public Utilities.
184. Madison G&E	Madison Gas & Electric Company.
185. Maine Public Service	Maine Public Service Company.
186. Maritime	Maritime Electric Company.
187. McKenzie EC	McKenzie Electric Cooperative, Inc.
188. MD Com	Maryland Public Service Commission.
189. ME Consumer-Owned Utilities	Maine Consumer-Owned Utilities (consisting of Eastern Maine Electric Cooperative, Inc., Fox Islands Electric Cooperative, Inc. Houlton Water Company, Isle au Haut Electric Power Co., Kennebunk Light & Power District, Madison Electric Works, Swans Island Electric Cooperative, Inc., and Van Buren Light & Power District).
190. ME Industrials	Industrial Energy Consumer Group of Maine.
191. MEAG	Municipal Electric Authority of Georgia.
192. Memphis	Memphis Light, Gas and Water Division.
193. Mercer	Mercer, Dorothy Ph.D.
194. MI Com	Michigan Public Service Commission.
195. MI MEA	Municipal Energy Agency of Mississippi.
196. Michigan Coalition	Consumers Power, Detroit Edison and Michigan Public Service Commission.
197. Michigan Systems	Florida Municipal Power Agency, Michigan Public Power Agency, Michigan South Central Power Agency, Michigan Public Power Ratepayers Association and Wolverine Power Supply Cooperative.
198. MidAmerican	MidAmerican Energy Company.
199. Midwest Commissions	Arkansas, Kansas & Missouri State Commissions.

200. Minnesota P&L	Minnesota Power & Light Company.
201. Missouri Basin Group	Missouri Basin Systems Group, Inc.
202. Missouri Basin MPA	Missouri Basin Municipal Power Agency.
203. Missouri Joint Commission	Missouri Joint Municipal Electric Utilities Commission.
204. Missouri-Kansas Industrials	Missouri-Kansas Industrial Energy Consumers.
205. MMWEC	Massachusetts Municipal Wholesale Electric Company.
206. MN DPS	Minnesota Department of Public Service.
207. Montana Power	Montana Power Company.
208. Montana-Dakota Utilities	Montana-Dakota Utilities Company.
209. Montaup	Montaup Electric Company.
210. Mor-Gran-Sou EC	Mor-Gran-Sou Electric Cooperative.
211. Mountain States Petroleum Assoc	Independent Petroleum Association of Mountain States and Colorado Oil and Gas Association.
212. MS Com	Mississippi Public Service Commission.
213. MT Com	Montana Public Service Commission.
214. MT Dept of Environmental Quality	Montana Department of Environmental Quality.
215. Mt. Hope Hydro	Mt. Hope Hydro, Inc.
216. Municipal Energy Agency Nebraska	Municipal Energy Agency of Nebraska.
217. NARUC	National Association of Regulatory Utility Commissioners.
218. NASUCA	National Association of State Utility Consumer Advocates.
219. National Hydropower	National Hydropower Association.
220. National Women's Caucus	National Women's Political Caucus.
221. Natural Resources Defense	Natural Resources Defense Council and Pacific Gas and Electric Company.
222. NC Com	North Carolina Utilities Commission.
223. NCMPA	North Carolina Municipal Power Agency Number 1.
224. NCPA	Northern California Power Agency.
225. ND Com	North Dakota Public Service Commission.
226. NE Public Power District	Nebraska Public Power District.
227. NE States Air Management	Northeast States for Coordinated Air Use Management.

228. NEPCO	New England Power Company.
229. NEPOOL	New England Power Pool Executive Committee.
230. NEPOOL Review Committee	New England Public Power NEPOOL Review Committee.
231. NERC	North American Electric Reliability Council.
232. Nevada	Nevada Power Company.
233. New Brunswick	New Brunswick Power.
234. NGSA	Natural Gas Supply Association.
235. NH Com	New Hampshire Public Utilities Commission.
236. NH General Court	Retail Wheeling & Restructuring Committee of the New Hampshire General Court.
237. NIEP	National Independent Energy Producers.
238. NIMO	Niagara Mohawk Power Corporation.
239. NIPSCO	Northern Indiana Public Service Company.
240. NJ BPU	New Jersey Board of Public Utilities.
241. NJ Ratepayer Advocate	New Jersey Division of the Ratepayer Advocate.
242. NM Com	New Mexico Public Utility Commission.
243. NM Industrials	New Mexico Industrial Energy Consumers.
244. NorAm	NorAm Energy Services, Inc.
245. Nordhaus	Nordhaus, William D.
246. North Dakota RECs	North Dakota Association of Rural Electric Cooperatives.
247. NRECA	National Rural Electric Cooperative Association.
248. NRECA/APPA	National Rural Electric Cooperative Association and APPA.
249. NRRI	National Regulatory Research Institute.
250. NSP	Northern States Power Company.
251. NU	Northeast Utilities System Companies.
252. Nuclear Energy Institute	Nuclear Energy Institute.
253. Nucor	Nucor Corporation.
254. NV Com	Public Service Commission of Nevada.
255. NW Conservation Act Coalition	Northwest Conservation Act Coalition.

256. NW Iowa Cooperative	Northwest Iowa Power Cooperative.
257. NW Power Planning Council	Northwest Power Planning Council.
258. NWRTA	Northwest Regional Transmission Association.
259. NY AG	New York State Attorney General.
260. NY Com	Public Service Commission of the State of New York.
261. NY Consumer Protection	New York Consumer Protection Board
262. NY Energy Buyers	New York Energy Buyers Forum.
263. NY Industrials	Multiple Industrial Intervenors of New York.
264. NY IOUs	Long Island Lighting, New York State Electric & Gas and Rochester Gas & Elec.
265. NY Mayors	New York State Conference of Mayors and Municipal Officals.
266. NYMEX	New York Mercantile Exchange.
267. NYPP	New York Power Pool.
268. NYSEG	New York State Electric & Gas Corporation.
269. Oahe EC	Oahe Electric Cooperative, Inc.
270. Oak Ridge	Oak Ridge National Laboratory.
271. Occidental Chemical	Occidental Chemical Corporation.
272. Oglethorpe	Oglethorpe Power Corporation.
273. OH Com	Public Utilities Commission of Ohio.
274. OH Coops	Ohio Rural Electric Cooperatives, Inc. and Buckeye Power, Inc.
275. OH Industrials	Industrial Energy Users—Ohio.
276. Ohio Edison	Ohio Edison Company.
277. Ohio Manufacturers	Ohio Manufacturers' Association.
278. Ohio Valley	Ohio Valley Electric Corporation.
279. OK Com	Oklahoma Corporation Commission.
280. Oklahoma G&E	Oklahoma Gas and Electric Company.
281. Old Dominion EC	Old Dominion Electric Cooperative, Inc.
282. Oliver-Mercer EC	Oliver-Mercer Electric Cooperative, Inc.
283. Omaha PPD	Omaha Public Power District.

284. Ontario Hydro	Ontario Hydro.
285. Orange & Rockland	Orange and Rockland Utilities, Inc.
286. Oregon Trail EC	Oregon Trail Electric Cooperative, Inc.
287. Otter Tail	Otter Tail Power Company.
288. PA Com	Pennsylvania Public Utility Commission.
289. PA Coops	Pennsylvania Rural Electric Association and Allegheny Electric Cooperative, Inc.
290. PA Industrials	Industrial Energy Consumers of Pennsylvania.
291. PA Munis	Pennsylvania Municipal Electric Association.
292. Pacific Northwest Coop	Pacific Northwest Generating Cooperative.
293. PacifiCorp	PacifiCorp.
294. Panhandle Coop	Panhandle Rural Electric Membership Association.
295. PECO	PECO Energy Company.
296. Pennsylvania P&L	Pennsylvania Power & Light Company.
297. PG&E	Pacific Gas and Electric Company.
298. Phelps Dodge	Phelps Dodge Corporation.
299. Philip Morris	Philip Morris Management Corp.
300. PJM	PJM—Pennsylvania New Jersey Maryland Interconnection.
301. Portland	Portland General Electric Company.
302. Power Marketing Association	Power Marketing Association.
303. PSE&G	Public Service Electric and Gas Company.
304. PSNM	Public Service Company of New Mexico.
305. Public Generating Pool	Public Generating Pool.
306. Public Power Council	Public Power Council.
307. Public Service Co of CO	Public Service Company of Colorado and Cheyenne Light, Fuel and Power Company.
308. Puget	Puget Sound Power & Light Company.
309. Redding	Cities of Redding and Santa Clara, California.
310. Reynolds	Reynolds Metals Company.
311. Rochester G&E	Rochester Gas and Electric Corporation.

312. Rocky Mountain Institute	Rocky Mountain Institute (Amory Lovins).
313. Rosebud	Rosebud Enterprises, Inc.
314. RUS	Rural Utilities Service (formerly REA).
315. Rushmore EC	Rushmore Electric Power Cooperative, Inc.
316. Salt River	Salt River Project Agriculture Improvement and Power District.
317. San Diego G&E	San Diego Gas & Electric Company.
318. San Francisco	City and County of San Francisco.
319. San Luis Valley REC	San Luis Valley Rural Electric Cooperative.
320. SBA	United States Small Business Administration, Office of Advocacy.
321. SC Com	South Carolina Public Service Commission.
322. SCE&G	South Carolina Electric & Gas Company.
323. SC Public Service Authority	South Carolina Public Service Authority.
324. Seattle	Seattle City Light Department.
325. Seminole EC	Seminole Electric Cooperative, Inc.
326. SEPA	Southeastern Power Administration/Federal Power Customers.
327. Shelby County	Shelby County Board of Commissioners.
328. Sierra	Sierra Pacific Power Company.
329. Slope EC	Slope Electric Cooperative Inc.
330. SMUD	Sacramento Municipal Utility District.
331. Snohomish	Public Utility District No. 1 of Snohomish County, Washington.
332. SoCal Edison	Southern California Edison Company.
333. SoCal Gas	Southern California Gas Company.
334. South Jersey Gas	South Jersey Gas Company.
335. Southern	Southern Company Services, Inc.
336. Southwest TDU Group	Southwest Transmission Dependent Utility Group (consisting of Aguila Irrigation District, Ak-Chin Indian Community, Buckeye Irrigation District, Central Arizona Water Conservation District, Electrical District No. 3, No. 4, No. 5, No. 6, No. 7, Harquahala Valley Power

	District, Maricopa Water District, McMullen Valley Water Conservation and Drainage District, City of Needles, Roosevelt Irrigation District, City of Safford, Tonopah Irrigation District, Wellton-Mohawk Irrigation and Drainage District).
337. Southwestern	Southwestern Public Service Company.
338. Soyland	Soyland Power Cooperative.
339. Spink EC	Spink Electric, Redfield, SD.
340. SPP	Southwest Power Pool, Inc.
341. Springfield	City Utilities of Springfield, Missouri.
342. St. Joseph	St. Joseph Light & Power Company.
343. Suffolk County	Suffolk County (New York) Electric Agency.
344. Sunflower	Sunflower Electric Power Corporation.
345. Supervised Housing	State and City Supervised Housing for Equity in Electric Rates.
346. Sustainable Energy Policy	Project For Sustainable FERC Energy Policy (on behalf of Alliance for Affordable Energy, Citizens Action Coalition of Indiana, Conservation Law Foundation, Environmental Defense Fund, Environmental Law & Policy Center of the Midwest, Izaak Walton League of America, Land and Water Fund of the Rockies, Legal Environmental Assistance Foundation, Mid-Atlantic Energy Project, Minnesotans for an Energy-Efficient Economy, Natural Resources Defense Council, Northwest Conservation Act Coalition, Pace Energy Project, Public Citizen, Texas, RENEW Wisconsin, Southern Environmental Law Center, Texas Ratepayers' Organization to Save Energy, Union of Concerned Scientists, and Wisconsin's Environmental Decade).
347. Tallahassee	City of Tallahassee, Florida.
348. Tampa	Tampa Electric Company.
349. TANC	Transmission Agency of Northern California.
350. TAPS	Transmission Access Policy Study Group.
351. TDU Systems	Transmission Dependent Utility Systems (Arkansas Electric Cooperative Corporation, Connecticut Municipal Electric Energy Cooperative, Golden Spread Electric Cooperative, Inc., Holy Cross Electric Association, Inc., Kansas Electric Power Cooperative, Inc., Magic Valley Electric Cooperative, Inc., Mid-Tex Generation & Transmission Electric Cooperative, Inc., NewCorp Resources, Inc., Old Dominion Electric Cooperative, Inc.).
352. Texaco	Texaco Inc.

353. Texas Utilities	Texas Utilities Electric Company.
354. Texas-New Mexico	Texas-New Mexico Power Company.
355. Tonko	Tonko, Paul D. (NY State Assembly).
356. Torco	Torco Energy Marketing, Inc.
357. Total Petroleum	Total Petroleum, Inc.
358. Traverse EC	Traverse Electric Cooperative, Inc.
359. Tri-County EC	Tri-County Electric Association, Inc.
360. Tri-State G&T	Tri-State Generation and Transmission Association, Inc.
361. Tucson Power	Tucson Electric Power Company.
362. Turlock	Turlock Irrigation District.
363. Turner-Hutchinson EC	Turner-Hutchinson Electric Cooperative, Inc.
364. TVA	Tennessee Valley Authority.
365. TX Com	Public Utility Commission of Texas.
366. TX Industrials	Texas Industrial Energy Consumers.
367. UAMPS	Utah Associated Municipal Power Systems.
368. Union County EC	Union County Electric Cooperative, Inc.
369. Union Electric	Union Electric Company.
370. United Illuminating	United Illuminating Company.
371. UNITIL	UNITIL Corporation.
372. Urban League	Greater Washington Urban League, Inc.
373. UT Com	Utah Public Service Commission and Utah Division of Public Utilities.
374. UT Industrials	Utah Industrial Energy Consumers (consisting of Alliant Techsystems, Inc., Amoco Oil Company, Holnam, Inc., Kennecott Copper Corp., and Western Zirconium.
375. UtiliCorp	UtiliCorp United Inc.
376. Utilities For Improved Transition	Utilities For an Improved Transition (consisting of Basin Electric Cooperative, Black Hills Corporation, Boston Edison Company, Central Vermont Public Service Corporation, Montaup Electric Company, Wisconsin Electric Power Company, and Wisconsin Public Service Corporation).

377. Utility—Trade Corp. Utility—Trade Corp.

378. Utility Investors Analysts	Utility Investors and Analysts.
379. Utility Shareholders	United Utility Shareholders Association of America.
380. Utility Wind Interest Group	Utility Wind Interest Group, Inc.
381. Utility Workers Union	Utility Workers Union of America, AFL-CIO.
382. Utility Working Group	Utility Working Group (consisting of Atlantic City Electric Company, Dominion Resources, Inc., Duke Power Company, Florida Power & Light Company, Niagara Mohawk Power Corporation, Pacific Gas and Electric Company, Public Service Electric and Gas Company, and San Diego Gas & Electric Company).
383. VA Com	Staff of the Virginia State Corporation Commission.
384. Vann	Vann, Albert (NY State Assembly).
385. VEPCO	Virginia Electric and Power Company.
386. Verendrye EC	Verendrye Electric Cooperative, Inc.
387. Vernon	City of Vernon, California.
388. VT DPS	Vermont Department of Public Service.
389. WA Com	Washington Utilities and Transportation Commission.
390. Wabash	Wabash Valley Power Association, Inc.
391. WAPA	Western Area Power Administration and Department of Energy.
392. Washington and Oregon Energy Offices	Washington State Energy Office and Oregon Department of Energy.
393. Washington Water Power	Washington Water Power Company Energy Offices.
394. WEPCO	Wisconsin Electric Power Company.
395. West River EC	West River Electric Association, Inc.
396. Western Resources	Western Resources Inc.
397. Whetstone Valley EC	Whetstone Valley Electric Cooperative, Inc.
398. WI Com	Public Service Commission of Wisconsin.
399. Wing Group	Wing Group.
400. Wisconsin Coalition	Wisconsin Coalition (Wisconsin Public Power Incorporated System, Municipal Electric Utilities of Wisconsin, Madison Gas and Electric Company, and Citizens' Utility Board of Wisconsin).
401. Wisconsin EC	Wisconsin Electric Cooperative Association.

402. Wisconsin Municipals	Municipal Electric Utilities of Wisconsin.
403. Wollenberg	Wollenberg, Bruce, et al.
404. Wolverine Coop Members	Wolverine Power Supply Cooperative Special Members Committee.
405. Woodbury County REC	Woodbury County Rural Electric Cooperative.
406. WP&L	Wisconsin Power and Light Company.
407. WSCC	Western Systems Coordinating Council Board of Trustees.
408. WSPP	Western Systems Power Pool.
409. Yellowstone Valley EC	Yellowstone Valley Electric Cooperative, Inc.

21702** ***Environmental Impact Commenters

1. Attorneys General of Massachusetts, Connecticut, New Jersey and Vermont

2. Center for Clean Air Policy

3. Central Maine Power Company

4. Cincinnati Gas & Electric Company and PSI Energy, Inc.

5. Clifton Below

6. Electric Consumer's Alliance

7. Connecticut Siting Council

8. Southern Environmental Law Center

9. General Public Utilities Corporation

10. Public Advisory Committee of the Grand Canyon Visibility Transport Commission

11. Institute of Clean Air Companies

12. Interstate Natural Gas Association of America

13. Atlantic Electric Co. and Audubon Society of New Hampshire et al.

14. Maryland Department of Natural Resources and Maryland Energy Administration

15. Midwest Ozone Group

16. Missouri Department of Natural Resources

17. National Mining Association, Western Fuels Association, Inc. and the Center for Energy and Economic Efficiency

18. The Navajo Nation

19. Maine, Massachusetts, Vermont and New Hampshire Public Service Commissions

20. New Jersey Board of Public Utilities and the New Jersey Department of Environmental Protection

21. New York State Department of Public Service and the New York State Department of Environmental Conservation

22. Office of the Ohio Consumers' Counsel

23. Ohio Electric Utility Institute Environmental Committee

24. Ozone Transport Assessment Group

25. Ozone Transport Commission

26. Utility Air Regulatory Group (Edison Electric Institute, the National Rural Electric Cooperative Association and the American Public Power Association)

27. Wisconsin Department of Natural Resources

Other (Including Technical Conference Commenters)

1. Electric Power Research Institute

2. Electric Policy Technical Issues Group

3. Tejas Power Corporation

4. Competitive Power Coalition of New England

5. Mid-Continent Area Power Pool

6. Michigan Electric Coordinated Systems

7. Independent Energy Producers Association

8. Praxair, Inc.

9. Utility-Trade Corp.

10. Competitive Power Coalition of New England

11. Wyoming Public Service Commission

12. State of New Jersey

13. Paul Joskow

14. New England Conference of Public Utility Commissioners

15. Commonwealth of Massachusetts

16. Florida Electric Power Coordinating Group

17. Dine Power Authority

18. State of Connecticut Department of Environmental Protection

19. Commonwealth of Massachusetts Department of Environmental Protection

20. State of Maine Department of Environmental Protection

21. Comision Federal de Electricidad of Mexico

Appendix C—Allegations of Public Utilities Exercising Transmission Dominance

I. Examples From Proceedings Before Administrative Law Judges
These are examples of allegations that various public utilities have refused to ***21703** provide comparable service, either through refusals to wheel, dilatory tactics that so protracted negotiations as to effectively deny wheeling, refusals to provide service priority equal to native load, or refusals to provide service flexibility equivalent to the utility's own use.

A. American Electric Power Service Corp. (AEP)
In 1993, AEP filed, on behalf of its public utility associate companies, an open access tariff that offered only firm point-to-point service with very limited flexibility. It did not offer network service, flexible point-to-point service, or non-firm service. Thus, it did not provide customers with the same flexibility that AEP itself has. Nor did it provide a service priority equivalent to that enjoyed by native load. The Commission set AEP's tariff for hearing and, on rehearing, held that in order not to be unduly discriminatory, the tariff had to offer comparable service. American Electric Power Service Corp., 64 FERC 61,279 (1993), reh'g, 67 FERC 61,168 (1994).

At hearing, Raj Rao of Indiana Michigan Power Agency (IMPA) (Ex. IMPA-1, Feb 23, 1994) and Kenneth Hegemann of American Municipal Power-Ohio, Inc. (AMP-Ohio) (Ex. AMPO-1, Feb 23, 1994), both senior management officials, testified concerning AEP's alleged discriminatory practices.[FN1] AMP-Ohio is an association of municipalities in Ohio, some of whose members depend on AEP for transmission and partial requirements service. IMPA is an association of municipalities in Indiana, and many of IMPA's loads are captive to the AEP transmission system. The witnesses alleged as follows:

1. In anticipation of high peak demands, AEP would contract for large blocks of available short-term power, withhold sale of short-term power, refuse to transmit third party short-term power, and require purchases from AEP at the emergency rate (100 mill/kwh) when an emergency might not exist. Ex. AMPO-1 at 6.

2. In December 1989, AMP-Ohio negotiated a 20 MW purchase of short-term power from Louisville Gas & Electric Company (LG&E). AEP refused to wheel because LG&E had earlier that day told AEP it had no power to sell to AEP. AEP then bought the power from LG&E and offered to resell it to AMP-Ohio. Ex. AMPO-1 at 6-7.

3. In January 1990, AMP-Ohio solicited bids for February power purchases from a number of utilities including AEP. AEP was not the winning bid. AMP-Ohio made arrangements to purchase the power from four winning bidders and sought transmission through AEP. When AMP-Ohio gave AEP the schedule for delivery, AEP refused to transmit the power, matched the average price of the winning bids, and made the sale itself. Ex. AMPO-1 at 7.

4. In August 1993, an AMP-Ohio member (Columbus, Ohio) was purchasing 10 MW of hourly non-displacement power from AEP and, after AEP raised its price to 60 mills/kwh, sought another source for the next hour. Consumers Power Company and Detroit Edison Company both offered non-displacement power at 40 mills. AEP refused to transmit, saying it had a 600 MW unit out and could not resell power from another source.[FN2] Columbus cancelled the transaction and had to buy 10 MW of power from AEP at 100 mills/kwh. Ex. AMPO-1 at 7-8.

5. In July 1993, two AMP-Ohio members (Columbus and St. Mary's) had been buying hourly non-displacement power from AEP when the price rose to 35 mills. Dayton Power & Light Company (DP&L) offered to sell at 23 mills and AEP agreed to transmit for one hour. But for the next hour, AEP said it had problems with its system, refused to transmit the power, kept

the power from DP&L for itself and offered to sell power to AMP-Ohio for Columbus and St. Mary's at 100 mills. Columbus increased its local generation, but St. Mary's purchased 8 MW at 100 mills. For the next hour, AMP-Ohio arranged with DP&L for another 8 MW, hoping AEP would transmit under the 24 hour buy-sell agreement. AEP did transmit this power. Seven hours later in the day, St. Mary's Greenup Hydro project power was available and the 8 MW from DP&L was no longer needed. If St. Mary's had been receiving the hourly power that AEP had refused to transmit, St. Mary's could have switched to Greenup power. But because AMP-Ohio had changed to daily service, St. Mary's had to pay a demand charge for the entire day, even though it used the power only 7 hours and would have paid less under the hourly rate. Ex. AMPO-1 at 8-9.

6. In January 1994, AMP-Ohio sought to transfer power from one member with generation to other members, which required transmission over AEP and Toledo Edison lines. Toledo Edison said yes, AEP said no. AMP-Ohio's northern members purchased emergency power from Toledo Edison. AMP-Ohio then reminded AEP that it had agreed not to deny transmission and AEP agreed to transmit. Ex. AMPO-1 at 9.

7. IMPA arranged to buy 80 MW of short-term power from LG&E and have it wheeled, using buy-sell arrangements, through Public Service Company of Indiana (PSI) and AEP to serve IMPA's load at Richmond (an IMPA member). The delivered price was $.292 per kW-day plus a 1 mill adder. At the same time AEP arranged to buy 300 MW from PSI at $.30 per kW day plus out-of-pocket energy costs. Hence, PSI was shipping a total of 380 MW to AEP with 80 MW of that amount to be delivered to IMPA's load at Richmond. Then, on a day when IMPA should have received the 80 MW, AEP told IMPA that PSI had sold everything to AEP and that IMPA would have to buy from AEP at $.63 per kW day plus the cost of energy from AEP. IMPA purchased from AEP under protest. AEP used its control over transmission to intercept the 80 MW at a lower price and resell it as short-term power to IMPA. AEP claimed that PSI had terminated its sales to AEP on that day. But the 80 MW was independent of PSI's other sales to AEP and would not have been interrupted if AEP had not interrupted it. IMPA-1 at 7.

8. IMPA has combustion turbines owned by and located at one member, which IMPA would like to connect to the Joint Transmission System owned by IMPA, CINergy and Wabash Valley Power Association. To do so, IMPA needed a metering agreement with AEP, to which AEP would not agree. IMPA-1 at 6.

9. In January 1994, IMPA had power to sell from its turbines when AEP and others needed power. IMPA offered power to AEP but AEP it said could not purchase the power without an existing contract. Moreover, since there was no short-term tariff, IMPA could not sell the power to another utility. IMPA-1 at 6.

10. Another example of the utility engaging in dilatory tactics that raised the customer's transaction costs and effectively denied transmission is the "sham transaction" provision proposed by AEP. As filed, AEP's tariffs permitted it to deny service merely because a portion of the transmitted power might be used to serve a former retail customer of AEP. See, e.g., Ex. BR&WVP-1 (J. Bertram Solomon testimony, February 23, 1994). (As part of a settlement AEP filed the pro forma tariff and withdrew this provision.)

11. Finally, AEP's originally filed tariff contained a "prodigal customer" provision. Under this provision, transmission customers who sought to convert back to requirements service had to give AEP five years' notice, in which case AEP and the customer would enter into negotiations to determine whether AEP will provide service at all and if so under what rate, terms, and conditions. Ex. S-39 at 1 (Staff testimony). AEP did not require notice from all new customers, only from prodigal customers. Id. at 2. That a potential customer was previously served by AEP is not a reason to treat the customer differently. (AEP withdrew this provision when it filed the pro forma tariff.)

B. Entergy Services, Inc. (Entergy)

Entergy filed a partial settlement largely adopting the NOPR pro forma tariffs except for two provisions (headroom and ancillary services). Because the settlement predated the filing date for customer testimony before the ALJ, the customers did not address the need for Entergy to file a tariff. However, customers did make allegations of discriminatory practices, as follows.

1. Customers alleged that Entergy flat-out refused to wheel. Louisiana Energy and Power Authority (LEPA) witness Sylvan J. Richard testified that LEPA's predecessor systems could not obtain interconnections from Entergy. Ex. SJR-1 at 50.

2. Customers also alleged that Entergy refused to provide service priority equal to native load and refused to provide service flexibility equivalent to the utility's own use. For example, LEPA witness Richard testified that even after state commissions ordered interconnections and other coordination ***21704** services, LEPA's predecessors were still not able to obtain coordination services because Entergy was not willing to coordinate and because the transmission service it did offer was inflexible, unidirectional point-to-point service, which prevented economic coordination with others. Id. at 50-51.

3. South Mississippi Electric Power Association (SMEPA) witness J. Bertram Solomon testified that Entergy's original "open access" tariff was restricted to point-to-point service, proposed separate charges for each operating company, and required the cancellation of existing agreements in order to take service under the proposed tariff. Ex. SMEPA-10 at 28. Entergy eventually filed a network tariff, but proposed different local facilities charges for the various Entergy public utility operating subsidiaries. Id. at 29. Since these local facilities charges were higher than the transmission component of the subsidiaries' bundled rates, Entergy obtained a competitive advantage. Id.

4. The Arkansas Cities and Cooperatives (ACC) is a group of cities and cooperatives that own or operate electric generation or distribution systems in Arkansas. ACC Witness Steven Merchant testified that Entergy has segregated the wholesale market between two of its subsidiaries, Arkansas Power & Light Copmpany (APL) and Entergy Power, Inc. (EPI). Ex. SMM-1 at 16. In marketing power and energy in Arkansas, EPI is subject to an Arkansas Commission order that bars EPI from competing with APL for wholesale loads without first obtaining a waiver. Id. Recently, EPI requested this waiver for all wholesale transactions in Arkansas except for wholesale customers currently served by an Entergy subsidiary; in other words, EPI requested the Arkansas Commission to expand competition for all wholesale customers except where EPI might compete with APL. Id. ACC witness Merchant concluded that, since EPI does not compete with APL, Entergy insulates APL's wholesale business from competition and denies those wholesale customers access to EPI as a source of power, thereby limiting alternative generation sources available to ACC. Id. at 17-19. (Entergy's witness Kenney stated that Entergy has recently filed a joint motion with ACC to the Arkansas Commission seeking to extend the waiver and permit EPI to sell to APL's wholesale customers. Ex. JFK-11 at 14-15.)

C. Pacific Gas & Electric Company (PG&E)

Northern California Power Agency (NCPA) attached several documents to its 1988 complaint in Docket No. EL89-4. These documents were provided to support NCPA's claim that PG&E's unreasonable practices under the PG&E/NCPA Interconnection Agreement (IA) effectively denied NCPA access to transmission properly requested under the IA. Although the parties eventually settled and the Commission terminated the docket with a letter order dated May 18, 1988, these documents provide allegations of PG&E using dilatory tactics that so protracted negotiations as to effectively equal a refusal to wheel.[FN3]

1. PG&E stated that since transmission was not currently available, it was entitled to wait 72 months before providing transmission; that is, transmission access could not be granted before the passing of the 72-month notice period. NCPA 1988 Complaint, Ex. 3. However, the IA provided that transmission be provided when it becomes actually available. PG&E also requested substantial additional information, which NCPA considered beyond that reasonably necessary for a study, but still provided. PG&E then determined that transmission was not available, reasoning that transmission was unavailable unless all the transmission requested could be provided 8760 hours per year without restrictions or limitations, extending through the expiration of the agreement in 2013. NCPA 1988 Complaint at 9.

2. On November 27, 1987, NCPA made a new transmission request to PG&E, seeking 50 MW of bi-directional transmission at Midway. NCPA 1988 Complaint, Ex. 5. On January 28, 1988, PG&E filed an interconnection agreement with Turlock Irrigation District (TID) that provided TID with 50 MW of bi-directional transmission at Midway. Pacific Gas & Electric Company, 42 FERC 61,406, order on reh'g, 43 FERC 61,403 (1988). On February 22, 1988, PG&E advised NCPA that all firm transmission service available at Midway had been fully subscribed. NCPA 1988 Complaint, Ex. 6. Then, on March 29, 1988, PG&E filed

with the Commission an interconnection agreement with Modesto Irrigation District (MID), that provided MID with 50 MW of bi-directional transmission at Midway. Pacific Gas & Electric Company, 44 FERC 61,010 (1988). At about the same time (in the last week in March 1988), PG&E advised NCPA that the allocations of transmission to TID, MID, and others, including a not yet finalized allocation to Sacramento Municipality Utility District, had used all the transmission available at Midway. NCPA 1988 Complaint, Exs. 7 and 8.

D. Northeast Utilities Service Company (NU)

This is the case where Northeast Utilities acquired Public Service of New Hampshire (PSNH) (Docket No. EC90-10). New England Power Company (NEP) witness Robert Bigelow's direct testimony expressed concern over the "relatively restrictive transmission policies of both" NU, on behalf of Northeast Utilities' public utility subsidiaries, and PSNH. Bigelow Direct Testimony at 21 (filed May 25, 1990). In his cross rebuttal testimony, Mr. Bigelow testified that "NU has a poor track record as a provider of transmission service" and "PSNH also has an abhorrent track record as a provider of transmission services." Bigelow Cross Rebuttal Testimony, at 3 (filed June 20, 1990). Mr. Bigelow described both NU's and NEP's (his own company) failure to provide service flexibility equivalent to their own use. Except for NEP's TDUs, both NEP and NU historically provided only point-to-point transmission, which required separate scheduling for each transaction. Bigelow Cross Rebuttal at 4.

E. Southern California Edison Company and San Diego Gas and Electric Company

The evidence in this merger proceeding (Docket No. EC89-5) included testimony from a number of witnesses describing instances of Edison's conduct. Richard Greenwalt was the power supply supervisor for the City of Riverside, California. He was responsible for scheduling all purchases of energy for Riverside and for the cities of Azusa, Banning and Colton, California. Greenwalt testimony at 1 (November 1989). (These four cities and Anaheim, California, are collectively referred to as the Southern Cities or Cities.) Joseph Hsu was the Director of Utilities for Azusa. Hsu testimony at 1 (November 1989). Gale Drews was the electric utility director of Colton. Drews testimony at 1-2 (November 1989). Bill Carnahan was the director for Riverside. Carnahan testimony at 1 (November 1989). Gordon Hoyt was the general manager of the Anaheim power department. Hoyt testimony at 1 (November 1989). Dan McCann was the power coordination supervisor for Anaheim. He supervised Anaheim's load scheduling and is a former Edison employee, having worked for Edison for 20 years. McCann Testimony at 1-2 (November 1989). These witnesses testified that Edison refused to wheel as follows.

1. Edison's policy was to curtail the Cities any time it could be justified using any of a list of acceptable reasons to deny interruptible transmission service. Id. at 22-23.

2. Edison would not generally provide transmission service when Edison could save money by itself purchasing the economy energy that would be wheeled. McCann testimony at 19. The Cities called Edison every hour to request interruptible transmission service. Id. Edison often refused to sell energy available in the Western Systems Power Pool to the Cities and then made available higher cost contract energy or partial requirements service. Id. at 19-20.

3. When Anaheim requested Edison provide firm transmission of power from neighboring states, Edison would often agree to provide non-firm service but would not integrate the capacity for many years in the future, saying that its control area did not need capacity at that time. Hoyt testimony at 9. Since the selling utility was interested in a sale of capacity, not just energy, the transaction would not occur. Id. Edison repeatedly used its control over transmission to deny Anaheim access to low-cost firm power. Id. at 9-10.

4. While Edison provided short-term firm transmission service to the Cities, it would only provide long-term firm service for three specific resources: The SONGS nuclear plant, a specific IPP, and Hoover Dam power. Hoyt testimony at 20. One of Edison's reasons for denying long-term transmission was that Edison desired to reserve the transmission for its own future (unspecified) needs. Id.

5. In the 1970s, Edison refused to allow the Cities access to the Pacific Intertie. Hoyt testimony at 21; Drews testimony at 7-8.

***21705** 6. In 1988, Edison refused to provide transmission service for a Cities power purchase from Public Service Company of New Mexico (PSNM) from Palo Verde Nuclear station. Hoyt testimony at 21.

7. Edison has refused to provide requested firm transmission from

—California-Oregon border to Midway Station

—Nevada-Oregon Border to Sylmar Substation

—Palo Verde Switchyard to Vista

—SONGS Switchyard to Vista.

Carahan testimony at 15.
8. Riverside requested transmission from Palo Verde and was told that such service was not available. Carnahan testimony at 16. Edison offered Riverside only 12 MW of curtailable transmission entitlement to provide Riverside's share of Palo Verde. Id. This service was neither large enough or long enough, and Edison insisted on unreasonable terms and conditions. Id.

9. Azusa, Banning and Colton had a contract with Edison that entitled them to use their Palo Verde firm transmission path to schedule energy to meet their contract energy obligation. Edison refused to permit the three cities to use that path. Edison did not contest that the contracts allowed this use, but said that the scheduling of such small amounts of energy for the three cities would be too burdensome. Greenwalt testimony at 14.

10. Edison would not respond in a timely manner to the Cities' requests, routinely taking months to respond. Drews testimony at 15.

11. During the 1980s, Edison provided Colton with some transmission service to allow the Cities to reach certain suppliers, but limited the choices available to the Cities and imposed terms and conditions that increased the Cities' costs and placed Colton at a disadvantage against Edison. Drews testimony at 9. Arranging alternative generation sources was difficult because the Cities always had to first get Edison to state whether it would provide transmission.

12. During 1988 and 1989, a dispute arose between Edison and the Cities concerning the Hoover Uprating Project. Drews testimony at 16. Edison argued that for the months when units were out of service for uprating, and Southern Cities capacity was reduced to zero, Southern Cities would not receive an energy credit, even though energy was still available and used by Edison. But the contracts allowed a participant who did not have capacity to still schedule its energy as non-firm energy on the capacity of another participant. Id. at 16-17.

13. In 1986, Azusa negotiated a power purchase contract with the California Department of Water Resources in increments of first 5 MW and then 2 MW (for a total of 7 MW). Hsu testimony at 14. First Edison assured Azusa that the transmission for the additional 2 MW would not be a problem. Id. Then Edison would not agree to amend the transmission service agreement for the additional 2 MW. Id.

14. In 1986, Azusa notified Edison of Special Condition 12[FN4] purchases from PG&E and requested firm transmission service. Id. Two months before service was to begin, Edison notified the Cities of a problem with the transmission lines. Id. Transmission was eventually granted, but only after a four-month delay and substantial losses to the Cities. Id. Then Edison decided there was no problem with its transmission facilities. Id. at 14-15.

15. In 1986-87, the Cities purchased 20 MW from PG&E and 80 MW from Deseret G&T Cooperative. Hoyt testimony at 7-8. Edison stated that without reinforcement of its transmission system, Edison would not provide the transmission. Id. There was a

five-month delay during which the Cities were forced to purchase from Edison at a higher cost. Id. at 8-9. Then Edison decided that the transmission system did not need reinforcement. Id. at 8.

16. Edison also refused to provide a service priority equal to that of native load. It would curtail the Cities in order to purchase more economy energy for itself. McCann testimony at 28. If Edison could make the purchase, it would curtail the City and use the energy for itself. Id. When Edison curtailed the Cities, they were not able to purchase economy energy and instead purchased energy from Edison. Id. at 24.

17. According to Edison, the interruptible transmission it provided the Cities was interruptible for any reason. Id. at 20. A purchase could be terminated the hour after it is begun or even during the hour. Id. As a result, the Cities lost opportunities to make advantageous economy purchases. Id. at 20-21.

18. Edison also refused to provide customers flexibility similar to the flexibility Edison provided itself. Edison's refusal to provide bi-directional transmission service restricted the Cities' abilities to purchase hydroelectric energy from the Pacific Northwest. Hoyt testimony at 22. Because most contracts with Northwest utilities require a return of power, the Northwest utilities would not deal with the Cities without transmission to return energy. Id. at 22-23. Edison did provide bi-directional transmission to the Los Angeles Department of Water & Power (LADWP) to accommodate flows to and from Arizona. Id.

19. Riverside was unable to obtain non-firm service more than two hours in advance of need. Carnahan testimony at 18.

20. Riverside and Colton were both served out of Edison's Vista substation. Although the two cities were on the same 69 kV bus, Edison would not allow them to sell energy to each other. Greenwalt testimony at 17.

21. Riverside's agreement with Edison allowed Riverside to purchase a block of energy through the WSPP and divide it up among the four Cities (Azusa, Banning, Colton and Riverside). Greenwalt testimony at 17. When Riverside had excess energy from other sources, Edison would not permit it to sell that energy to the other three cities. Id. For example, Riverside attempted to sell Deseret energy transmitted by LADWP to the Edison system. Id. at 17-18. LADWP would not break out the Cities' shares of that energy, and Edison would not accept the energy as a delivery for all four cities. Id. at 18. Edison argued that because this energy was excess energy that Riverside could not use, Riverside did not have transmission rights to bring it into the control area. Id. As a result, Riverside paid for the energy delivered by LADWP to the Edison control area, but could not sell it to the other three cities, and gave it to Edison itself, which consumed the energy without making any payment for it. Id. Riverside tried a number of alternative paths, including using WSPP transmission where Riverside paid Edison 5 mills to connect to Azusa, 5 mills to connect to Banning, and 5 mills to connect to Colton for each megawatthour. While this approach was successful for a while, eventually Edison refused to permit these sales.

22. Edison claimed that the Cities only have transmission rights to bring in enough Special Condition 12 energy to satisfy the Cities' load. Greenwalt testimony at 18.

23. Edison contended that the Cities' load requirements were satisfied first by integrated resources and then by Special Condition 12 and economy energy purchases. Id. at 19. When the Cities' integrated resources exceeded their load, any Special Condition 12 resources became excess. Under Riverside's Deseret contract, the Cities were required to take a minimum of 35 MW each hour. Id. Edison acknowledged that it was obligated to buy, or allow the Cities to sell, any excess energy from Riverside's integrated resources. Id. However, Edison refused to give the Cities credit for excess Special Condition 12 energy brought into the area, claiming that the Cities could not have brought it in because they did not have transmission rights. Id.

II. Other Examples of Transmission Disputes

Disputes over transmission are not uncommon, contrary to EEI's suggestion. Some recent examples taken from pleadings and other documents and from Commission orders reveal that it has been very difficult for various entities in the electric power industry to agree on transmission rights. These examples also reveal that even after issuance of AEP and the Open Access

NOPR with its proposed pro forma tariffs, there has been considerable controversy over whether various utilities' "open access" tariffs deviate from those tariffs. (The Commission has allowed utilities that adopt tariffs that match or exceed the non-rate terms and conditions in the NOPR pro forma tariffs to obtain certain benefits.)

A. In a letter of February 3, 1995 to Mr. Gerald Richman of the Commission's Enforcement section in the Office of the General Counsel, Steven J. Kean, Vice President, Regulatory Affairs, Enron Power Marketing, Inc. (Enron) alleged that Niagara Mohawk Power Corporation (NiMo) refused to wheel power from Rochester Gas & Electric (RG&E) to Enron under RG&E's transmission contract with NiMo; however, when Enron revealed the buyer, NiMo did wheel power for RG&E to the buyer. Mr. Kean alleged that this was not an isolated incident. NiMo argued that the contract did not require it to ***21706** provide RG&E with transmission to Enron. It also said that the principle of comparability does not require the service. Letter of November 21, 1994 from NiMo representative A. Karen Hill to Gerald Richman.

B. The Commission's Task Force Hot Line (Hot Line) received a complaint that a member of the New York Power Pool (NYPP) refused to transmit power that another member bought from a power marketer. In a letter of November 17, 1994, from Chair Moler to Mr. William J. Balet, Executive Director of NYPP, Chair Moler explained that the Commission's enforcement staff had investigated and found the allegation to be true.

C. In Southern Minnesota Municipal Power Agency v. Northern States Power Company (Minnesota), 73 FERC 61,350 (1995), NSP and SMMPA had a contract under which NSP agreed to provide transmission service. However, the parties had numerous disputes over the service. The Commission found that NSP had misinterpreted the contract in several ways. For, example, SMMPA argued that it should be able to directly schedule its deliveries of energy out of the NSP control area and that it should not be limited to particular points of delivery. NSP argued that only it was entitled to control the physical operation of scheduling. The Commission found that the clear language of the contracts gave SMMPA the authority to schedule its own power.

D. Mid-Continent Area Power Pool, 72 FERC 61,223 (1995), involved MAPP's membership criteria, which made it impossible for a power marketer to join MAPP and obtain the benefits of certain transmission services available only to MAPP members. The Commission found that the membership criteria may be unreasonable, particularly since there may be less burdensome ways of setting up membership criteria for non-traditional entities.

Appendix D—Pro Forma Open Access Transmission Tariff

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I. Common Service Provisions

1. Definitions

1.1 Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Annual Transmission Costs: The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 Commission: The Federal Energy Regulatory Commission.

1.5 Completed Application: An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.6 Control Area: An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

***21708** (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.7 Curtailment: A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.8 Delivering Party: The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.9 Designated Agent: Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.10 Direct Assignment Facilities: Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.11 Eligible Customer: (i) Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale; electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled Transmission Service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Transmission Provider.

1.12 Facilities Study: An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.13 Firm Point-To-Point Transmission Service: Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.14 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.15 Interruption: A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.16 Load Ratio Share: Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III the Tariff and calculated on a rolling twelve month basis.

1.17 Load Shedding: The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.18 Long-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.19 Native Load Customers: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.20 Network Customer: An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.21 Network Integration Transmission Service: The transmission service provided under Part III of the Tariff.

1.22 Network Load: The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.23 Network Operating Agreement: An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.24 Network Operating Committee: A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.25 Network Resource: Any designated generating resource owned or purchased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.26 Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.27 Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.28 Open Access Same-Time Information System (OASIS): The information system and standards of conduct contained in Part 37 of the Commission's regulations.

1.29 Part I: Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II: Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III: Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties: The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.33 Point(s) of Delivery: Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement.

1.34 Point(s) of Receipt: Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement.

1.35 Point-To-Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser: The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.37 Receiving Party: The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38 Regional Transmission Group (RTG): A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently ***21709** coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.39 Reserved Capacity: The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.40 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date: The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.42 Short-Term Firm Point-To-Point Transmission Service: Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.43 System Impact Study: An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.44 Third-Party Sale: Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.45 Transmission Customer: Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.46 Transmission Provider: The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.47 Transmission Provider's Monthly Transmission System Peak: The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.48 Transmission Service: Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.49 Transmission System: The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transmission Capability: For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control

Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5 and 6) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. If the Transmission Provider offers an affiliate a rate discount, or attributes a discounted Ancillary Service rate to its own transactions, the Transmission Provider must offer at the same time the same discounted Ancillary Service rate to all Eligible Customers. Information regarding any discounted Ancillary Service rates must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service: The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service: Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service: Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve—Spinning Reserve Service: Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve—Supplemental Reserve Service: Where applicable the rates and/or methodology are described in Schedule 6.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR part 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public ***21710** Utilities). In the event available transmission capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide Transmission Service to any Eligible Customer pursuant to this Tariff if the provision of such Transmission Service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such Transmission Service.

5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act and shall provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate affiliates. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure: Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default: In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues: Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues: Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification: The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, ***21711** arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures
12.1 Internal Dispute Resolution Procedures: Any dispute between a Transmission Customer and the Transmission Provider involving Transmission Service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) The cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) One half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. Point-To-Point Transmission Service

Preamble
The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term: The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority: Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. After the deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements: The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Firm Point-To-Point Transmission Service. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer under the Tariff will be specified in the Service Agreement prior to initiating service.

***21712** 13.6 Curtailment of Firm Transmission Service: In theevent that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, Curtailments will be proportionally allocated among the Transmission Provider's Native Load Customers, Network Customers, and Transmission Customers taking Firm Point-To-Point Transmission Service. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement along with a corresponding capacity reservation associated with each Point of Receipt. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement along with a corresponding capacity reservation associated with each Point of Delivery. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour (or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider). Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes (or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider) before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term: Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after July 9, 1996 or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements: The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in ***21713** the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to bc received and to be delivered.

14.7 Curtailment or Interruption of Service: The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, or (4) transmission service for Network Customers from non-designated resources. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions: The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transmission Capability: A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transmission capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement: If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

15.5 Deferral of Service: The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules: Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers: Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d. The Transmission Customer agrees to pay for any facilities constructed and ***21714** chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

e. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application: A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point

Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

18 CFR § 35.19a

17.3 Deposit: A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point

Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application: Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transmission capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1.

17.6 Execution of Service Agreement: Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service: The Transmission Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved ***21715** Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application: Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application: A Completed Application shall provide all of the information included in 18 CFR §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service: Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transmission Capability: Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transmission capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service. [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the

Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the maximum charge, based on the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the ***21716** Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications: Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities: The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service: If the Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20 Procedures if the Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions: When the review process of Section determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions: If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions: The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems ***21717** which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis: Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service: Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service: In accordance with Section 4, Resellers may use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations: Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data: The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. Network Integration Transmission Service

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

***21718** *28 Nature of Network Integration Transmission Service*

28.1 Scope of Service: Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service: The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service: The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses: Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service: The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.

29 Initiating Service

29.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G.

29.2 Application Procedures: An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection), which shall include, for each Network Resource:

—Unit size and amount of capacity from that unit to be designated as Network Resource

—VAR capability (both leading and lagging) of all generators

—Operating restrictions

—Any periods of restricted operations throughout the year

—Maintenance schedules

—Minimum loading level of unit

—Normal operating level of unit

—Any must-run unit designations required for system reliability or contract reasons

—Approximate variable generating cost ($/MWH) for redispatch computations

—Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource

—Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;
(vi) Description of Eligible Customer's transmission system:

—Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider

—Operating restrictions needed for reliability

—Operating guides employed by system operators

—Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources

—Location of Network Resources described in subsection (v) above

—10 year projection of system expansions or upgrades

—Transmission System maps that include any proposed expansions or upgrades

—Thermal ratings of Eligible Customer's Control Area ties with other Control Areas; and
(vii) Service Commencement Date and the term of the requested Network Integration ***21719** Transmission Service. The minimum term for Network Integration Transmission Service is one year.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities: The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement: The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

Network Resources

30.1 Designation of Network Resources: Network Resources shall include all generation owned or purchased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources: The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service pursuant to an Application under Section 29.

30.3 Termination of Network Resources: The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

30.4 Operation of Network Resources: The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load plus losses.

30.5 Network Customer Redispatch Obligation: As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources: The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load Ratio Share.

30.9 Network Customer Owned Transmission Facilities: The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the planning and operations of the Transmission Provider to serve all of its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load: The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider: The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected with the Transmission Provider: This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission ***21720** Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points: To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates: The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures for Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study: After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the maximum charge, based on the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33 Load Shedding and Curtailments

33.1 Procedures: Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever ***21721** actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding: To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth ($^1/_{12}$) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load: The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge: The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery: The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and the [applicable regional reliability council], (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

***21722 Schedule 1—Scheduling, System Control and Dispatch Service**

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 2— Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Control Area where the Transmission Provider's transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Schedule 3—Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the

Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 4—Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

The Transmission Provider shall establish a deviation band of +/ 1.5 percent (with a minimum of 1 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.

Schedule 5—Operating Reserve—Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 6—Operating Reserve—Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Schedule 7—Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

(1) Yearly delivery: one-twelfth of the demand charge of $____/KW of Reserved Capacity per year.

(2) Monthly delivery: $____/KW of Reserved Capacity per month.

(3) Weekly delivery: $____/KW of Reserved Capacity per week.

(4) Daily delivery: $____/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(5) Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own ***21723** transactions, the Transmission Provider must offer at the same time the same discounted Firm Point-To-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any firm transmission discounts must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

Schedule 8—Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

(1) Monthly delivery: $____/KW of Reserved Capacity per month.

(2) Weekly delivery: $____/KW of Reserved Capacity per week.

(3) Daily delivery: $___/KW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

(4) Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $____/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

(5) Discounts: If the Transmission Provider offers an affiliate a rate discount or attributes a discounted transmission rate to its own transactions, the Transmission Provider must offer at the same time the same discounted Non-Firm Point-To-Point Transmission Service rate to all Eligible Customers on the same path and on all unconstrained transmission paths. Information regarding any non-firm transmission discounts must be posted on the OASIS pursuant to Part 37 of the Commission's regulations. In addition, discounts to non-affiliates must be offered in a not unduly discriminatory manner.

Attachment A—Form Of Service Agreement for Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________, is entered into, by and between ________ (the Transmission Provider), and ________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in the amount of $____, in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (1) ________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on ________.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Transmission Customer:

7.0 The Tariff is incorporated herein and made a part hereof.

In Witness Whereof, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

Name

Title

Date

Transmission Customer:

By:

Name

Title

Date

Specifications for Firm Point-To-Point Transmission Service

1.0 Term of Transaction:

Start Date:

Termination Date:

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

3.0 Point(s) of Receipt:

Delivering Party:

4.0 Point(s) of Delivery:

Receiving Party:

5.0 Maximum amount of capacity and energy to be transmitted

(Reserved Capacity):

6.0 Designation of party(ies) subject to reciprocal service obligation:

7.0 Name(s) of any Intervening Systems providing transmission service:
8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:

8.2 System Impact and/or Facilities Study Charge(s):

8.3 Direct Assignment Facilities Charge:

8.4 Ancillary Services Charges:

Attachment B—Form Of Service Agreement For Non-Firm Point-To-Point Transmission Service
1.0 This Service Agreement, dated as of ______, is entered into, by and between ______, (the Transmission Provider), and ______, (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Transmission Customer:
7.0 The Tariff is incorporated herein and made a part hereof.

In Witness Whereof, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

Name

Title

Date

Transmission Customer:

By:

Name

Title

Date

***21724 Attachment C—Methodology To Assess Available Transmission Capability**
To be filed by the Transmission Provider.

Attachment D—Methodology for Completing a System Impact Study
To be filed by the Transmission Provider.

Attachment E—Index Of Point-To-Point Transmission Service Customers

Customer
Date of Service Agreement

Attachment F—Service Agreement for Network Integration Transmission Service
To be filed by the Transmission Provider.

Attachment G—Network Operating Agreement
To be filed by the Transmission Provider.

Attachment H—Annual Transmission Revenue Requirement for Network Integration Transmission Service
1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be ______.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

Attachment I—Index of Network Integration Transmission Service Customers

Customer
Date of Service Agreement

Appendix E—Group 1 Public Utilities

Alabama Power Company

Appalachian Power Company

Arkansas Power & Light Company

Atlantic City Electric Company

Baltimore Gas & Electric Company

Black Hills Power & Light Company

Cambridge Electric Light Company

Central Illinois Light Company

Central Power and Light Company

Central Vermont Public Service Corporation

Cheyenne Light, Fuel and Power Company

Cincinnatti Gas & Electric Company

Citizens Utilities Company

Columbus Southern Power Company

Commonwealth Edison Company

Commonwealth Electric Company

Connecticut Light & Power Company

Connecticut Valley Electric Company

Consumers Power Company

Dayton Power & Light Company

Delmarva Power & Light Company

Duke Power Company

Duquesne Light Company

Florida Power & Light Company

Florida Power Corporation

Georgia Power Company

Granite State Electric Company

Gulf Power Company

Gulf States Utilities Company

Holyoke Power & Electric Company

Holyoke Water Power Company

Idaho Power Company

IES Utilities, Inc.

Illinois Power Company

Indiana Michigan Power Company

Interstate Power Company

Jersey Central Power & Light Company

Kansas City Power & Light Company

Kansas Gas & Electric Company

Kentucky Power Company

Kentucky Utilities Company

Kingsport Power Company

Louisiana Power & Light Company

Louisville Gas & Electric Company

Maine Public Service Company

Massachusetts Electric Company

Metropolitan Edison Company

MidAmerican Energy Company

Midwest Energy, Inc.

Minnesota Power & Light Company

Mississippi Power Company

Mississippi Power & Light Company

Monongahela Power Company

Montana Power Company

Montaup Electric Company

Nantahala Power & Light Company

Narragansett Electric Company

Nevada Power Company

New England Power Company

New Orleans Public Service Inc.

Northern Indiana Public Service Company

Northern States Power Company(Wisconsin)

Northern States Power Company (Minnesota)

Ohio Power Company

Orange & Rockland Utilities, Inc.

Pacific Gas & Electric Company

PacifiCorp

PECO Energy Company

Pennsylvania Electric Company

Pennsylvania Power & Light Company

Pike County Light & Power Company

Portland General Electric Company

Potomac Edison Company

Potomac Electric Power Company

PSI Energy, Inc.

Public Service Company of Colorado

Public Service Company of New Mexico

Public Service Company of New Hampshire

Public Service Electric and Gas Company

Public Utility Company of Oklahoma

Puget Sound Power & Light Company

Rockland Electric Company

San Diego Gas & Electric Company

Savannah Electric and Power Company

South Carolina Electric & Gas Company

Southern California Edison Company

Southern Indiana Gas & Electric Company

Southwestern Electric Power Company

Southwestern Public Service Company

Tampa Electric Company

United Illiminating Company

UtiliCorp United, Inc.

Washington Water Power Company

West Penn Power Company

West Texas Utilities Company

Western Massachusetts Electric Company

Western Resources, Inc.

Wheeling Power Company

Wisconsin Electric Power Company

Wisconsin Power & Light Company

Wisconsin Public Service Corporation

Note: Transmission tariffs have also been filed for some public utilities associated with pending merger applications. These individual utilities are not included in Group 1 and will be required to file tariffs on compliance with the Final Rule. They are: Centerior's filing for Cleveland Electric Illuminating Company and Toledo Edison Company; Interstate Energy Corporation's filing for South Beloit Water, Gas & Electric Company; Resources West's for Sierra Pacific Power Company; and the rate filing associated with the merger of Union Electric Company and Central Illinois Public Service Company.

Appendix F—Group 2 Public Utilities

Arizona Public Service Company

Bangor Hydro-Electric Company

Blackstone Valley Electric Company

Boston Edison Company

Carolina Power & Light Company

Central Hudson Gas & Electric Corporation

Central Illinois Public Service Company

Central Louisiana Electric Company, Inc.

Central Maine Power Company

Cleveland Electric Illuminating Company

Commonwealth Edison Company of Indiana

Concord Electric Company

Consolidated Edison Company of New York Inc.

Consolidated Water Power Company

Detroit Edison Company

Eastern Edison Company

Edison Sault Electric Company

El Paso Electric Company

Electric Energy Inc.

Empire District Electric Company

Exeter & Hampton Electric Company

Fitchburg Gas & Electric Light Company

Green Mountain Power Corporation

Indiana-Kentucky Electric Corporation

Indianapolis Power & Light Company

Kanawha Valley Power Company

Lockhart Power Company

Long Island Lighting Company

Long Sault, Inc.

Madison Gas & Electric Company

MDU Resources Group, Inc.

Mt. Carmel Public Utility Company

New England Electric Transmission Corporation

New England Hydro Transmission Electric Company

New England Hydro Transmission Corporation

New York State Electric & Gas Corporation

Newport Electric Corporation

Niagara Mohawk Power Corporation

Northwestern Public Service Company

Northwestern Wisconsin Electric Company

Ohio Edison Company

Ohio Valley Electic Corporation

Oklahoma Gas & Electric Company

Old Dominion Electric Cooperative

Otter Tail Power Company

Pennsylvania Power Company

Peoples Electric Cooperative

Rayburn Country Electric Cooperative

Rochester Gas & Electric Corporation

Sierra Pacific Power Company

South Beloit Water, Gas & Electric Company

St. Joseph Light & Power Company

Superior Water, Light and Power Company

Texas-New Mexico Power Company

Toledo Edison Company

Tucson Electric Power Company

UGI Utilities, Inc.

Union Electric Company

Union Light, Heat & Power Company

Unitil Power Corporation

Upper Penninsula Power Company

Vermont Electric Transmission Company

Vermont Electric Power Company

Virginia Electric & Power Company

Yadkin, Inc.

***21725 Appendix G**

I. Legal Analysis of Commission Jurisdiction Over the Rates, Terms and Conditions of Unbundled Retail Transmission in Interstate Commerce

Based on an analysis of the relevant legislative history and case law under the Federal Power Act (FPA), the Commission concludes that it has exclusive jurisdiction over the rates, terms and conditions of the unbundled transmission in interstate commerce, by a public utility, of electric energy to an end user. This is also known as retail wheeling in interstate commerce. [FN1]

The Commission's jurisdiction over the rates, terms and conditions of transmission in interstate commerce derives from Congress' power to regulate interstate commerce under the United States Constitution[FN2] and the FPA. When Congress enacted the FPA, it gave the Commission exclusive jurisdiction over the rates, terms and conditions of transmission in interstate commerce by public utilities. The Supremacy Clause of the Constitution provides that federal laws enacted pursuant to the powers delegated to the federal government by the United States Constitution are the supreme law of the land.[FN3] Accordingly, to the extent that retail wheeling involves transmission in interstate commerce by public utilities, the rates, terms and conditions of such service are subject to the exclusive jurisdiction of the Commission, and must be filed with the Commission.[FN4]

1. Relevant Federal Power Act Provisions

Section 201(b)(1) of the FPA provides:

The provisions of this Part shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce * * *. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction * * * over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

16 U.S.C. 824(b)(1) (emphasis added). Thus, the statute on its face limits Commission jurisdiction over sales of energy to sales at wholesale, but does not limit jurisdiction over transmission to transmission used only for wholesale sales.

Sections 201 (c) and (d) define the meaning of "the transmission of electric energy in interstate commerce" and "sale of electric energy at wholesale in interstate commerce." Section 201(c) provides:

For the purpose of this Part, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof: but only insofar as such transmission takes place within the United States.

16 U.S.C. 824(c). Section 201(d) provides:

The term "sale of electric energy at wholesale" when used in this Part means a sale of electric energy to any person for resale.

16 U.S.C. 824(d).

Sections 205 and 206 of the FPA give the Commission jurisdiction over the rates, terms and conditions of transmission in interstate commerce, and sales at wholesale in interstate commerce, by public utilities. 16 U.S.C. 824d and 824e.

2. Legislative History and Case Law

Much of the legislative history of the FPA indicates that Congress intended the Commission's jurisdiction to extend only to those matters which the Attleboro decision[FN5] held to be beyond the reach of the States. For instance, the report accompanying the Senate bill states that subsection (b) "leaves to the States the authority to fix local rates even in cases where the energy is brought in from another State."[FN6] In other words, states retain authority to regulate rates of electric energy to ultimate consumers. The Senate report also states:

The rate-making powers of the Commission are confined to those wholesale transactions which the Supreme Court held in (Attleboro) to be beyond the reach of the States. Jurisdiction is asserted also over all interstate transmission lines whether or not there is sale of the energy carried by those lines and over the generating facilities which produce energy[FN7] for interstate transmission and sale.

S. Rep. No. 621, 74th Cong., 1st Sess. 48 (1935) (emphasis added). Thus, federal jurisdiction over transmission lines is not dependent on whether those lines are used to effect a sale, wholesale or otherwise.

The provisions of FPA section 201 reserving certain regulatory authority to the States have been interpreted narrowly.[FN8] The Supreme Court has stated:

In section 201(b), Congress did no more than leave standing whatever valid state laws then existed relating to the exportation of hydroelectric energy; by its plain terms, section 201(b) simply saves from pre-emption under Part II of the Federal Power Act such state authority as was otherwise "lawful."[FN9]

The Court also stated:

Nothing in the legislative history or language of the statute evinces a congressional intent 'to alter the limits of state power otherwise imposed by the Commerce Clause,' * * * or to modify the earlier holding of this Court concerning the limits of state authority to restrain interstate trade.[FN10]

Unlike the narrow interpretations given to the FPA provisions reserving certain regulatory authority to the States,[FN11] the courts have construed transmission "in interstate commerce" broadly. The term does not turn on whether the contract path for a particular power or transmission sale crosses state lines, but rather follows the physical flow of electricity. Because of the highly integrated nature of the electric system, this results in most transmission of electric energy being "in interstate commerce."

One of the earliest cases construing Commission jurisdiction over transmission was Jersey Central Power & Light Co. v. FPC, 319 U.S. 61 (1943) (Jersey Central). In that case, the Commission asserted jurisdiction over a New Jersey utility by showing that the utility owned transmission facilities that were used to transmit energy in interstate commerce. The Court found that the Commission had demonstrated that the utility owned transmission facilities that were indirectly interconnected, through a second New Jersey utility, to facilities owned by a New York utility and that the facilities were used to transmit electric energy in interstate commerce.

The Court noted that section 201(c) of the FPA defines electric energy transmitted in interstate commerce to be energy "transmitted from a State and consumed at any point outside thereof." The Court stated:

It is impossible for us to conclude that this definition [of transmission in interstate commerce] means less than it says and applies only to the energy at the instant it crosses the state line and so only to the facilities which cross the line and only to the company which owns the facilities that cross the line.

319 U.S. at 71. Thus, a critical question regarding the jurisdictional status of a wheeling transaction is whether the facilities used to provide the service transmit electric energy in interstate commerce.

*21726 In Connecticut Light & Power Co. v. FPC, 324 U.S. 515 (1945) (CL&P), the Court reviewed the Commission's finding that a Connecticut utility was jurisdictional because it owned transmission facilities that were used in interstate commerce. The Court generally embraced the Jersey Central standard for determining whether facilities are used to transmit electric energy in interstate commerce. The Court emphasized that whether certain facilities transmit electric energy in interstate commerce is more a technical than a legal question. The Court stated:

Federal jurisdiction was to follow the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental, test.

324 U.S. at 529. Thus, the Court adopted the Jersey Central test providing that the Commission's jurisdiction generally extends to transmission facilities that transmit electric energy in interstate commerce.

The Court also applied the Jersey Central test in FPC v. Florida Power & Light Co., 404 U.S. 453 (1972), affirming the Commission's finding of jurisdiction over a Florida utility. The Commission demonstrated that the utility transmitted power to another Florida utility's "bus"[FN12] and that power was simultaneously transferred from the "bus" to a Georgia utility. The Court upheld the Commission's finding that electric energy from the two Florida utilities was commingled and was therefore transmitted in interstate commerce. 404 U.S. at 463.

In all of the above cases, the Court's decisions turned on whether energy being transmitted flowed in interstate commerce as a technical matter. The decisions did not turn on whether the transmission of energy flowing in interstate commerce involved energy that was being sold for resale or was being sold to an end user. Thus, there is nothing in the statute, its legislative history, or the case law to indicate that the Commission's jurisdiction over rates, terms and conditions of transmission in interstate commerce extends only to wholesale transmission and not retail transmission. Indeed, the statute on its face gives the Commission jurisdiction over transmission in interstate commerce and makes no distinction between wholesale transmission and retail transmission.

However, there are two important limitations on Commission authority. First, as discussed above, the FPA does not give the Commission jurisdiction over sales of electric energy at retail. Such sales historically have been bundled sales (i.e., generation and transmission), and courts and the Commission have recognized State jurisdiction over bundled sales of energy. Second, under section 201(b)(1) of the FPA, the Commission does not have jurisdiction over facilities used in local distribution. In CL&P, the Court stated that local distribution facilities are exempt from Commission jurisdiction even if those facilities "carry no energy except extra-state energy." 324 U.S. at 531.

In the next section the Commission further discusses the statutory provisions and case law that shed light on the demarcation between transmission and local distribution, and thus on the jurisdictional line between federal and State authority.

II. Legal Analysis of Commission Jurisdictional Transmission Facilities and State Jurisdictional Local Distribution Facilities

Two specific circumstances are addressed:

First, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

Second, what facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to an end user?

Based on an analysis of the relevant legislative history and case law under the FPA, the Commission reaches the following conclusions. With respect to the first circumstance, the Commission concludes that a public utility's facilities used to deliver electric energy to a wholesale purchaser, whether labeled "transmission," "distribution," or "local distribution" are subject to the Commission's exclusive jurisdiction under sections 205 and 206 of the FPA, and that a public utility's facilities used to deliver electric energy from the wholesale purchaser to the ultimate consumer are "local distribution" facilities subject to the rate jurisdiction of the state. [FN13]

With respect to the second circumstance, the Commission believes that, based on the particular facts of the case, some of the public utility's facilities used to deliver electric energy to an end-user may be FERC-jurisdictional transmission facilities, while some of the facilities used may be state-jurisdictional local distribution facilities.

We set forth below the relevant legislative history and case law, our legal conclusions, and the factors which we believe are indicative of whether facilities are used in "local distribution" or "transmission in interstate commerce," as those terms are used in the FPA.

1. Relevant Federal Power Act Provisions

The Commission's jurisdiction is set forth in section 201 of the FPA. [FN14] Section 201(b)(1) provides in pertinent part:

The provisions of this Part shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce * * *. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction * * * over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.[FN15]

Some of the court decisions that construe jurisdictional facilities under section 201 also construe the Commission's jurisdiction under section 203. Section 203(a) provides, in relevant part:

No public utility shall sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, * * * or by any means whatsoever, directly or indirectly, merge or consolidate such facilities or any part thereof with those of any other person * * * without first having secured an order of the Commission to do so.[FN16]

In addition, section 206(d) concerns facilities "under the jurisdiction of the Commission":

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.[FN17]

2. Legislative History of the FPA

The relevant legislative history of the general purposes of Title II of the FPA, and of section 201 in particular, focuses primarily on bundled sales of electric energy and does not directly address the issue of what constitutes local distribution as opposed to transmission in interstate commerce.

In discussing the general purposes of Title II of the House bill, the House Report states:

Title II * * * establishes for the first time regulation of electric utility companies transmitting energy in interstate commerce.
* * * * *

* * * Under the decision of the Supreme Court of the United States in (Attleboro), the rates charged in interstate wholesale transactions may not be regulated by the States. Part II gives the Federal Power Commission jurisdiction to regulate these rates. A "wholesale" transaction is defined to mean the sale of electric energy for resale and the Commission is given no jurisdiction over local rates even where the electric energy moves in interstate commerce.[FN18]

In its analysis of section 201, the House Report states:

As in the Senate bill no jurisdiction is given over local distribution of electric energy, and the authority of States to fix local rates is not disturbed even in those cases where the energy is brought in from another State.[FN19]

***21727** The Senate Report's discussion of the general purposes of the FPA states:

The decision of the Supreme Court in (Attleboro) placed the interstate wholesale transactions of the electric utilities entirely beyond the reach of the States. Other features of this interstate utility business are equally immune from State control either legally or practically.[FN20]

In discussing material differences between the final version of the Senate bill and the original version, the Senate Report states:

Subsection (b), formerly (a), which states the subject matter to which the part relates, has been clarified to make plain that it includes interstate transmission where there is no sale and excludes all facilities used only for production of transmission in intrastate commerce or in local distribution.[FN21]

In discussing section 201 of the Senate bill, the Senate Report further states:

The rate-making powers of the Commission are confined to those wholesale transactions which the Supreme Court held in (Attleboro) to be beyond the reach of the States. Jurisdiction is asserted also over all interstate transmission lines whether or not there is sale of the energy carried by those lines and over the generating facilities which produce energy for interstate transmission and sale. It is obvious that no steps can be taken to secure the planned coordination of this industry on a regional scale unless all of the facilities, other than those used solely for retail distribution, are made subject to the jurisdiction of the Commission. Facilities used only for intrastate commerce or local distribution are expressly excluded from the operation of the act.[FN22]

The Conference Report adds little description regarding jurisdictional facilities. In reference to section 201(b) it states that:

[T]he language of the House amendment has been followed with a clarifying phrase added to remove any doubt as to the Commission's jurisdiction over facilities used for the generation and local distribution of electric energy to the extent provided in other sections of this part and the part next following.[FN23]

In addition to the above statements pertaining to section 201 of the FPA, Congress referenced distribution of energy in the legislative history of section 206(d). Section 206(d) was originally enacted as section 206(b) of the FPA. Under the Regulatory Fairness Act of 1988,[FN24] section 206(b) was redesignated as section 206(d).

The Conference Report on the original FPA does not address section 206(b). The Senate Report on the FPA bill states in pertinent part:

Subsection (b) authorizes the Commission to investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy. * * * Since the rate-making powers granted to the Commission apply only to the wholesale rates of energy sold in interstate commerce, this last subsection should be of great benefit in removing the practical difficulty which the States may encounter in regulating the interstate distribution rates which are left under their control. Such rate regulation involves the examination and valuation of property outside the State. The task is one requiring an agency with a jurisdiction broader than that of a single State. The authority of the Federal Commission is to render assistance to the State commissions in a way which would preserve and make more effective the jurisdiction which is thus left to the States.[FN25]

The House Report discusses section 206(b) as follows:

This subsection reaches those situations where electric energy is transmitted in interstate commerce by the same company which distributes it locally, and will greatly aid State commissions in fixing reasonable rates in such cases.[FN26]

Thus, the discussions in the two reports do not appear to contemplate a situation in which the transmitter and seller of electric energy are different, and neither is a "local" distributor. The House Report expressly refers to the same company being the transmitter and seller of electric energy. The Senate Report by its terms addresses the regulation of interstate distribution rates.[FN27]

The above legislative history on sections 201 and 206(b) does not provide any definitive answers to the questions raised. We therefore turn to the case law under the FPA.

3. Case Law Under the FPA

Jersey Central was the first of the major FPC jurisdictional cases considered by the Supreme Court. The case involved the acquisition by New Jersey Power and Light Company (New Jersey Power) of certain securities of Jersey Central Power & Light Company (Jersey Central) without the Commission's prior approval. The question before the Court was whether Jersey Central was a "public utility" under section 201(e)[FN28] of the FPA so that the Commission's prior approval of the stock acquisition was necessary under section 203 of the FPA.

Jersey Central owned transmission facilities that connected to facilities that Public Service Electric & Gas Company (Public Service) owned. The interconnection of these transmission facilities was in New Jersey. Public Service's facilities in turn connected to the facilities of the Staten Island Edison Corporation (Staten Island Edison), a New York utility, at the mid-channel of Kill van Kull, a body of water separating New Jersey and New York. Jersey Central delivered energy to and received energy from Public Service under contract, and Public Service delivered energy to and received energy from Staten Island Edison under contract.[FN29]

The Court found that, although Jersey Central generated and received electricity only in New Jersey, some of the electric energy that it dispatched to Public Service "was instantaneously transmitted to New York."[FN30] The Court held that "[t]his evidence * * * furnishes substantial basis for the conclusion of the Commission that facilities of Jersey Central are utilized for the transmission of electric energy across state lines."[FN31] Therefore, the Court found that Jersey Central was a public utility within the meaning of section 201(e).[FN32]

The Court cited Attleboro, in which the Court found that the sale of locally produced electric energy for use in another state resulted in the transmission of electric energy in interstate commerce, even though title passed at the state line.[FN33] In Jersey Central, the Court explained the rationale for federal jurisdiction as follows:

(Section 201(c) of the FPA) defines the electric energy in commerce as that "transmitted from a State and consumed at any point outside thereof." There was no change in this definition in the various drafts of the bill. The definition was used to "lend precision to the scope of the bill." It is impossible for us to conclude that this definition means less than it says * * *. The purpose of this act was primarily to regulate the rates and charges of the interstate energy.[FN34]

The Court in Jersey Central thus interpreted the FPA as placing within the federal province regulation of wholesale sales of electric energy that, in any manner, flows in interstate commerce. The language quoted above and the citation to section 201(c) of the FPA, to be relied upon in subsequent Supreme Court cases, strongly suggested that the Commission's jurisdiction was not based on whether there was a sale by the utility, but rather on the flow of electric energy either into or out of a state, so long as the energy crosses state lines.

CL&P, which was decided two years after Jersey Central, is the leading case interpreting ***21728** the section 201(b) local distribution proviso. In CL&P, the Commission sought to regulate the accounting practices of Connecticut Light & Power Company (CL&P).[FN35] At issue was whether CL&P was a "public utility" under the FPA. The utility's system encompassed an area solely within a single state (Connecticut)[FN36] and did not interconnect with any other company that operated out of state.[FN37] "Its purchases and sales, its receipts and deliveries of power, (were) all within the state."[FN38] However, CL&P did purchase energy from companies that had, in turn, purchased energy from Massachusetts. The company also sold energy to a municipality that exported a portion of that energy to Fishers Island, located off the coast of Connecticut but "territory of New York."[FN39] The Commission based its jurisdiction on these few transactions.[FN40]

The Court of Appeals affirmed the Commission, holding that the Commission's jurisdiction extended to "electric distribution systems which normally would operate as interstate businesses." The Court of Appeals found that:

Whether or not the facilities by which petitioner distributes energy from Massachusetts should be classified as 'local' is not relevant to this case. The sole test of jurisdiction of the Commission over accounts is whether these facilities, 'local' or otherwise, are used for the transmission of electric energy from a point in one state to a point in another.([FN41])

The Supreme Court reversed. It held that the statutory language in section 201(b) of the FPA providing that the Commission "shall not have jurisdiction * * * over facilities used in local distribution" is a limitation upon Commission jurisdiction that "the Commission must observe and the courts must enforce."[FN42] In analyzing the statute, the Court stated:

It has never been questioned that technologically generation, transmission, distribution and consumption are so fused and interdependent that the whole enterprise is within the reach of the commerce power of Congress, either on the basis that it is, or that it affects, interstate commerce, if at any point it crosses a state line.

* * * * *

But whatever reason or combination of reasons led Congress to put the provision in the Act, we think it meant what it said by the words "but shall not have jurisdiction * * * over facilities used in local distribution." Congress by these terms plainly was trying to reconcile the claims of federal and local authorities and to apportion federal and state jurisdiction over the industry.[FN43]

The Court decided that this limitation on jurisdiction was "a legal standard that must be given effect in this case in addition to the technological transmission test."[FN44]

The Court stated that whether or not local distribution facilities carried out-of-state electric energy was irrelevant. Whatever the origin of the electric energy they carried, so long as the utility used the lines for local distribution,[FN45] they were exempt from federal jurisdiction.[FN46] In fact, the Court stated that local distribution facilities "may carry no energy except extra-state energy and still be exempt under the Act." Id. at 531. The Court concluded that the Commission's order:

Must stand or fall on whether this company owned facilities that were used in transmission of interstate power and which were not facilities used in local distribution.[FN47]

Upon reversing the Court of Appeals, the Court commented, in dictum, on the evidence the Commission had relied upon in finding that the facilities in question were used for transmission. It noted that the Commission had relied upon certain gas transportation cases in concluding that transmission extends from the generator to the point where the function of conveyance in bulk over distance is completed and the process of subdividing the energy to serve ultimate consumers, which is the characteristic of "local distribution," is begun. The Court cautioned:

But a holding that distributing gas at low pressure to consumers is a local business is not a holding that the process of reducing it from high to low pressure is not also part of such local business. In so far as the Commission found in these cases a rule of law which excluded from the business of local distribution the process of reducing energy from high to low voltage in subdividing it to serve ultimate consumers, the Commission has misread the decisions of this Court. No such rule of law has been laid down.[FN48]

The Court also noted in its dictum, however, that once a company is properly found to be a "public utility" under the Act, the fact that a local commission may also have jurisdiction does not preclude exercise of the Commission's functions. Id. at 533.[FN49] The Court instructed the lower court to remand the case to the Commission for a finding regarding whether the facilities in question were used in local distribution.[FN50]

The CL&P case was ultimately disposed of without the Commission having made a finding that the facilities were used in local distribution. While the Commission found that it was "extremely doubtful" that it could find that the facilities in question were not local distribution facilities, 6 FPC 104, 106 (1947), the Commission did not articulate a definition of local distribution facilities.

In Wisconsin-Michigan Power Co. v. Federal Power Commission, [FN51] the Seventh Circuit held that a utility was a jurisdictional public utility where it operated two divisions in Wisconsin and Michigan in a coordinated manner such that electric energy from one state was transmitted to the other, and vice versa, "in appreciable amounts by the power company and by it commingled with energy generated in the two respective districts and then delivered to the [wholesale] customers * * *."[FN52] The court also rejected the notion that the energy changed its form or character when it was stepped down in voltage before it reached the wholesale purchasers.[FN53]

The court in Wisconsin-Michigan distinguished between transmission and local distribution by focusing on wholesale sales of electric energy versus retail sales ("local rates") of electric energy. It cited the House Report on the FPA, and characterized the legislative history as follows:

The legislative history, (H.R. Rep. No. 1318), 74th Cong., 1st Sess. pages 7, 8 and 27 (1935), discloses that the Congressional Committee intended that the provisions of the (FPA) should apply to the transmission of electric energy in interstate commerce, i.e., the sale of energy at wholesale in interstate commerce, but not to the retail sale of any such energy in local distribution; that the (FPA) left to the state the authority to fix local rates where the energy is brought in from other states, and that the rate making power of the (FPC) was to be confined to those wholesale transmissions which the Supreme Court had held in (Attleboro) to be beyond the reach of the state. Under that decision, said the committee, the rates charged in interstate wholesale transactions could not be regulated by the states. It defined a wholesale transaction as the sale of electric energy for resale.[FN54]

The Seventh Circuit's characterization of the House Report seems to equate transmission of electric energy in interstate commerce with the sale of energy at wholesale in interstate commerce. However, this interpretation is at odds with both the ***21729** plain words of the statute as well as the language of the House Report, both of which refer to transmission in interstate commerce separately from sales for resale in interstate commerce.[FN55] In addition, the Senate Report, which the Seventh Circuit did not mention, clearly recognized jurisdiction over all interstate transmission lines, whether or not a sale of energy is carried by those lines.[FN56]

The Wisconsin-Michigan court also cited analogous natural gas cases, stating that "[t]he question is essentially, when does interstate commerce transportation end and where do the local distribution facilities first become operative."[FN57] The court further stated that:

(U)pon delivery to (the wholesaler) local distribution begins when he resells. His sales and distribution at retail are clearly local in character, and constitute only local distribution; but at no point before delivery to him has been completed, has interstate transmission terminated. In other words, "facilities used in local distribution" means facilities used for making resale and distribution to consumers, jurisdiction over which is left to the states. It was only because of this conclusion that the Supreme Court said, (citation omitted), the Act "cut(s) sharply and cleanly between sales for resale and direct sales for consumptive uses." We think there is no ground for the position that local distribution includes any transmission occurring before the wholesaler who resells at retail is reached.[FN58]

The Seventh Circuit concluded that the sales for resale were made in interstate commerce; that local distribution had not begun; that the interstate character of the transmission persisted until delivery to the wholesaler; that, up to that point, no local distribution facilities were in operation and that, therefore, the sales were subject to Commission regulation.

In Federal Power Commission v. Southern California Edison Company (the Colton case),[FN59] the Supreme Court held that the FPA provides a clear line of demarcation between jurisdictional transactions and non-jurisdictional transactions. However, this case, too, involved bundled sales of electric energy. In the facts of the case, Southern California Edison Company (Edison) admitted that it was a public utility by virtue of owning two interstate transmission lines.[FN60] At issue was whether its sales of electric energy to the City of Colton, California, for resale to Colton's retail customers, were jurisdictional. Included in the electric energy that Edison sold to Colton was out-of-state electric energy from Hoover Dam.[FN61] The Commission ruled that the sale to Colton was a sale of electric energy at wholesale in interstate commerce subject to regulation under the FPA.[FN62] In upholding the Commission, the Court held that Edison's importation of out-of-state electricity for resale to Colton sufficed to confer federal jurisdiction.

The Court, citing an earlier Supreme Court case,[FN63] characterized Congressional intent in the FPA:

(W)hat Congress did was to adopt the test developed in the Attleboro line which denied state power to regulate a sale "at wholesale to local distributing companies" and allowed state regulation of a sale at "local retail rates to ultimate consumers."[FN64]

The Court rejected the argument that FPC jurisdiction was confined to those interstate wholesale sales constitutionally beyond the power of state regulation by force of the Commerce Clause, and was to be determined on a case-by-case analysis of the impact of state regulation upon the national interest. The Court stated that in the FPA:

(C)ongress meant to draw a bright-line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis. This was done in the Power Act by making FPC jurisdiction plenary and extend[ed] it to all wholesale sales in interstate commerce except those which Congress has made explicitly subject to regulation by the States.[FN65]

The Court held that "(t)here is no such exception covering the Edison-Colton sale."[FN66]
Parties in the Colton case had raised the question of whether jurisdiction over the Colton sale was prevented by the "local distribution" proviso of section 201(b). The Court stated that whether facilities are local distribution facilities is a matter for the Commission to decide in the first instance. Citing CL&P, supra, it stated:

Whether facilities are used in local distribution—although a limitation on FPC jurisdiction and a legal standard that must be given effect in addition to the technological transmission test * * *—involves a question of fact to be decided by the FPC as an original matter.[FN67]

The Court cited evidentiary support and the Commission's expertise in such matters in upholding the Commission's determination that certain facilities owned by Edison were used exclusively to effect the wholesale sale to Colton and not for local distribution. Such facilities included 12 kV lines that served an industrial customer, several lighted highway signs, a residence and a railroad section house before they reached the transformers in the Colton substation. The FPC had held that those uses prior to the lines reaching the Colton substation did not transform the lines into local distribution facilities.[FN68]

In Duke Power Company v. Federal Power Commission (Duke),[FN69] the D.C. Circuit held that a public utility's acquisition of facilities used solely in local distribution, and which would continue to be used for local distribution, was beyond the Commission's jurisdiction under section 203. The case involved Duke Power Company's (Duke's) proposed acquisition of facilities owned by Clemson University (Clemson), which were used to distribute electricity off-campus to customers (primarily university personnel) in two South Carolina counties. Clemson purchased the power at wholesale from Duke. No one appeared to contest the conclusion that the 7 miles of distribution line and 418 service connections owned by Clemson were "local distribution" facilities.[FN70] Rather, the case turned on interpreting section 203 and whether it was intended to affect only acquisitions of jurisdictional facilities, or also to affect acquisitions of non-jurisdictional facilities. In interpreting section 203, however, the D.C. Circuit extensively analyzed and discussed the fundamental jurisdictional lines that Congress drew in section 201.

Citing to the CL&P case, the court in Duke stated:

The Act, as we have seen, effectuated federal control over the transmission and the sale at wholesale of electric energy in interstate commerce, and established the Commission's regulatory power over public utilities engaging in either of these pursuits.[FN71]

However, quoting CL&P, the court further stated:
The expression "facilities used in local distribution" is one of relative generality. But as used in this Act it is not a meaningless generality in the light of our history and the structure of our government. We hold the phrase to be a limitation on jurisdiction and a legal standard that must be given effect in this case in addition to the technological transmission test.[FN72]

The court further rejected the Commission's concept that, in order to determine whether jurisdiction over any particular acquisition existed, the impact of local supervision be measured on a case-by-case basis. Quoting from Colton, the court stated:

[T]his "flexible approach"—involving as it does the consideration, inter alia, of "the ***21730** effect of the regulation upon the national interest in the commerce"—has been flatly rejected as a technique for resolving jurisdictional conflicts between the Commission and state bodies. * * * We think that like the line "(i)t cut sharply and cleanly between sales for resale and direct sales for consumptive uses" to facilitate jurisdictional determinations in rate regulation, "Congress meant to draw a bright line easily ascertained, between state and federal jurisdiction, making unnecessary such case-by-case analysis," in distributing regulatory power over the acquisition of facilities.[FN73]

The court rejected the Commission's argument that jurisdiction over the merger or consolidation of jurisdictional facilities with those of any other "person" under section 203 gave the Commission jurisdiction over Duke's acquisition. The court stated that the FPA reflects a policy "'that matters largely of a local nature, even though interstate in character, should be handled locally and should receive the consideration of local [officials] familiar with the local conditions in the communities involved.'"[FN74]
Federal Power Commission v. Florida Power & Light Company[FN75] is the last major court case to address the Commission's transmission jurisdiction. In this case, the Commission sought to impose its accounting rules upon Florida Power & Light Company (Florida Power & Light). The company's system lay solely within the borders of Florida and did not directly connect with any out-of-state utility.[FN76] The Commission held that Florida Power & Light did own facilities that transmitted electric energy in interstate commerce, but the Court of Appeals for the Fifth Circuit ruled that the Commission did not have substantial evidence to support its finding.

The Supreme Court reversed. The Supreme Court noted that Florida Power & Light was a member of the Florida Power Pool along with Florida Power Corporation (Florida Power Corp.).[FN77] In turn, Florida Power Corp. connected with Georgia Power Company (Georgia Power) at a "bus"[FN78] south of the Georgia-Florida border.[FN79] Florida Power Corp. regularly exchanged power with Georgia Power.[FN80] In many instances, Florida Power Corp. transferred power to Florida Power & Light instantly after receiving power from Georgia Power, and transferred power to Georgia Power immediately after receiving power from Florida Power & Light.[FN81] The Supreme Court found that power commingled in the bus moved across state lines, and concluded that Florida Power & Light engaged in transmission in interstate commerce. The Court held that, to establish jurisdiction, the Commission need only show that "some (Florida Power & Light) power goes out of State."[FN82] The Court further explained that "(i)f any (Florida Power & Light) power has reached Georgia, or (if Florida Power & Light) makes use of any Georgia power * * * FPC jurisdiction will attach * * *."[FN83]

There is also a line of cases that address, among other things, what constitutes a Commission jurisdictional "sale of electric energy at wholesale"[FN84] under section 201 of the FPA.[FN85] These cases all concerned bundled sales. While the issues posed above involve unbundled wheeling, the "resale" cases are helpful to the extent they suggest that local distribution takes place only after power is subdivided. See, e.g., 345 U.S. at 316 ("the facilities supplied 'local distribution' only after the current was subdivided for individual consumers.").

4. Natural Gas Act

The Natural Gas Act (NGA) was adopted in 1938. Like the FPA, the NGA contains language limiting the Commission's jurisdiction in situations involving local distribution.[FN86]

Section 1(b) of the NGA provides:

The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural.[FN87]

There is similarity in many respects between the House and Senate Reports on the FPA and the NGA with respect to the jurisdiction given the Commission. For example, all four reports mention Attleboro as placing interstate wholesale transactions beyond the reach of the States. As indicated in the House Report on the NGA, the States could "regulate sales to consumers even though such sales are in interstate commerce, such sales being considered local in character and in the absence of congressional prohibition subject to State regulation." (See H.R. Rep. No. 709, 75th Cong., 1st Sess. 1). However, the House and Senate Reports on the NGA contain identical language not found in the reports on the FPA:

In view of the importance of section 1(b), which states the scope of the act, it seems advisable to comment on certain provisions appearing therein. It will be noted that this subsection of the bill, after affirmatively stating the matters to which the act is to apply, contains a provision specifying what the act is not to apply to, as follows:

But shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

The quoted words are not actually necessary, as the matters specified therein could not be said fairly to be covered by the language affirmatively stating the jurisdiction of the Commission, but similar language was in previous bills, and, rather than invite the contention, however unfounded, that the elimination of the negative language would broaden the scope of the act, the committee has included it in this bill. That part of the negative declaration stating that the act shall not apply to "the local distribution of natural gas" is surplusage by reason of the fact that distribution is made only to consumers in connection with sales, and since no jurisdiction is given to the Commission to regulate sales to consumers the Commission would have no authority over distribution, whether or not local in character. (Emphasis added).[FN88]

As a result of this language it can be argued that Congress considered distribution (and local distribution) only in the context of bundled retail sales of natural gas. In fact, it appears that all of the court cases affirming the states' right to regulate local distribution of gas have involved bundled retail sales. See Panhandle Eastern Pipe Line Co. v. Michigan Public Service

Commission, 341 U.S. 329 (1951) (Panhandle). There the Court, in affirming the State of Michigan's right to regulate an interstate pipeline's proposed bundled retail sales of gas to industrial consumers, noted that the pipeline company proposed to lay pipeline in "the streets and alleys of Detroit" and ignored the local distribution company's request for additional gas to meet the increased needs of the industrial consumers. Id. at 333. While the Court based its holding on a state's authority to regulate direct (retail) sales to an end-user, rather than on the basis of the section 1(b) local distribution provision, it also found that the proposed sales were "primarily of local interest" and "emphasized the need for local regulation." Id. Two years before Panhandle, the Supreme Court issued its decision in FPC v. East Ohio Gas Co., 338 U.S. 465 (1949) (East Ohio). East Ohio Gas Company owned and operated a natural gas business wholly within the State of Ohio. The company sold gas only to Ohio customers but most of the gas was transported to Ohio from other states by interstate pipelines. These interstate pipelines connected inside Ohio with East Ohio's large high pressure lines. The gas then was transported over 100 miles through East Ohio's system to its local distribution system. East Ohio argued that it was exempt from Commission jurisdiction because all of its facilities were local distribution.

The Court disagreed, finding the Commission's jurisdiction extends over the ***21731** transportation of gas in interstate commerce through high-pressure transmission lines and that distribution did not begin until the point where pressure is reduced and gas enters local mains. The Court stated that: "[w]hat Congress must have meant by 'facilities' for 'local distribution' was equipment for distributing gas among customers within a particular local community, not the high-pressure pipelines transporting the gas to the local mains."[FN89]

The Commission relied in part on East Ohio's high pressure/low pressure distinction in a recent NGA section 7 certificate case which authorized construction of facilities to bypass the local distribution company.[FN90] On appeal, the California Commission argued that under section 1(b) it should at least have "jurisdiction over the 'taps, meters and other tie-in facilities' that link the pipeline to end users."[FN91] The court disagreed:

While as a matter of ordinary English 'local distribution' might be understood to encompass any delivery to an end user, that is hardly the only or even more plausible reading. Distribution conjures up receiving a large quantity of some good and parcelling it out among many takers.[FN92]

After reviewing the report language discussed above, the court also stated:

Insofar as congressional committees spoke to the matter * * * they appear to have viewed distribution as confined to its parcelling out function and (probably) even more narrowly, to parcelling out accompanied by retail sales.[FN93]

In Cascade Natural Gas Corporation v. FERC, et al. (Cascade), the court affirmed the Commission's authorizing an interstate pipeline under section 7 of the NGA "to construct a tap and meter facility that would allow it to deliver natural gas directly to two industrial consumers * * *."[FN94] To reach the interstate pipeline, the industrials constructed a nine-mile pipeline. Together, the facilities bypassed the local distribution company.[FN95]

The court rejected arguments that section 1(b) deprived the Commission of jurisdiction holding that:

"Local distribution," as Congress viewed the term, involves two components: the retail sale of natural gas and its local delivery, normally through a network of branch lines designed to supply local consumers.[FN96]

5. Analysis

a. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier to a purchaser who will then re-sell the energy to an end user?

The case law supports the conclusion that any facilities of a public utility used to deliver electric energy in interstate commerce to a wholesale purchaser, whether such facilities are labeled "transmission," "distribution" or "local distribution," are subject to the Commission's jurisdiction under sections 205 and 206.

This conclusion is supported by Public Utilities Commission, supra, in which the Supreme Court, in the section of its opinion addressing the section 201(b) local distribution provision, held that local distribution facilities began "only after the current was subdivided for individual consumers."[FN97] Wisconsin-Michigan, supra, in which the Seventh Circuit held that there is no local distribution until the wholesaler who re-sells at retail is reached, is to like effect.

This conclusion, which results in a "functional" line being drawn to determine Commission jurisdiction, is not only consistent with the case law under section 201, but is also consistent with our interpretation of the line drawn under newly amended FPA sections 211 and 212. As long as electric energy is being sold to a legitimate wholesale purchaser, we believe the Commission has jurisdiction under sections 201, 205, and 206 of the FPA over the public utility's facilities used to deliver electric energy to that purchaser.

b. What facilities are jurisdictional to the Commission in a situation involving the unbundled delivery in interstate commerce by a public utility of electric energy from a third-party supplier directly to an end user?

In analyzing jurisdiction over unbundled retail wheeling, we believe it is important to distinguish between unbundled wheeling provided by the public utility who previously provided bundled retail service to the end user, and unbundled wheeling provided by other public utilities to the end user. For example, a former bundled retail customer may need unbundled wheeling services from its previous public utility generation supplier, as well as unbundled wheeling from one or more intervening public utilities, in order to reach a distant generation supplier. In this scenario, the Commission believes it would have jurisdiction over all of the facilities used for the unbundled wheeling provided by the intervening public utilities.[FN98] The more difficult issue is whether some portion of the facilities used to transmit energy from the transmitting utility in closest proximity to the end user (the former supplier of the bundled product) is local distribution facilities. We believe that in most, if not all circumstances, some portion will be local distribution facilities.

The case law is replete with statements that the local distribution provision of section 201 must be given effect. However, the Supreme Court in both CL&P and Colton, supra, has stated that whether facilities are used in local distribution is a question of fact to be decided by the Commission as an original matter. Thus, there is no clear case law on a "bright line" between transmission and local distribution. In addition, regardless of the details of the chain of delivery services necessary to move electric energy from the generator to the end user, in most cases the last public utility in the chain will use facilities that historically were considered local distribution facilities. Accordingly, unlike the situation involving unbundled wholesale wheeling, for which the case law clearly supports a "functional" test, the Commission believes the case law and practical realities of a changing industry support an analysis of local distribution facilities based on the facilities' functional as well as technical characteristics.

While it would be preferable to draw an absolutely "bright" line (e.g., based on technical characteristics such as voltage), the Commission does not believe this is required by the case law and, importantly, would not be a workable approach in all cases because of the variety of circumstances that may arise and because utilities themselves classify facilities differently (e.g., one utility may classify a 69 kV facility as transmission; another may classify it as distribution).

Therefore, the Commission is adopting several indicators it will evaluate in determining whether particular facilities are transmission or local distribution in the case of vertically integrated transmission and distribution utilities:[FN99]

- Local distribution facilities are normally in close proximity to retail customers.

- Local distribution facilities are primarily radial in character.

- Power flows into local distribution systems, it rarely, if ever, flows out.

- When power enters a local distribution system, it is not reconsigned or transported on to some other market.

- Power entering a local distribution system is consumed in a comparatively restricted geographical area.

- Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.

- Local distribution systems will be of reduced voltage.[FN100]

In summary, for unbundled wholesale wheeling the Commission will apply a ***21732** functional test. The only definitive question will be whether the entity to whom the power is delivered is a lawful wholesaler. For unbundled retail wheeling the Commission will apply a combination functional-technical test that will take into account technical characteristics of the facilities used for the wheeling. The Commission concludes that these tests are consistent with the FPA, its legislative history and the case law discussed above.

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Appendix H.—Table ES-2.—National Emissions of NO_X as Projected in Both Base Cases and All Proposed Rule Scenarios

[Thousand tons]

Year	Under assumption that relative gas and coal prices remain constant		Under assumption that gas prices increase compared to coal prices		
	Constant price-differential base case	Competition-favors-gas proposed rule scenario	High-price-differential base case	Competition-favors-coal proposed rule scenario	Low response proposed rule scenario
1993	5,844	5,844	5,844	5,844	5,844
2000	5,362	5,255	5,672	5,763	5,743
2005	5,579	5,449	6,053	6,108	6,056
2010	5,772	5,638	6,426	6,519	6,426

***21733 Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities**

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

(As corrected April 25, 1996)

[Docket No. RM95-8-000; Docket No. RM94-7-001]

Issued April 24, 1996.
HOECKER, Commissioner, concurring in part and dissenting in part:

General Observations

A. Four years and untold numbers of conferences, studies, and speculations after the Energy Policy Act, the Commission today takes a major step in bringing competition to the wholesale bulk power market in the United States. Order No. 888 (FERC Stats. & Regs. 31,036), together with our order establishing an open access same-time information system (OASIS) (Order No. 889, FERC Stats. & Regs. 31,037) and our proposal to conform all transmission tariffs to a uniform capacity reservation system (FERC Stats. & Regs. 32,517), will set in motion a dynamism seldom witnessed in the electric power business. In that sense, the organizational, operational, and economic consequences of the requirements we adopt today defy prediction. I believe nevertheless that the Commission's Final Rule today is a sound and reasoned decision about the industry as we now know it and as we think it may evolve. I therefore announce my unequivocal support for the order's basic tenets as we have chosen to implement them—the unbundled wholesale utility services, open and non-discriminatory access to transmission and to information about transmission, service comparability, an opportunity for increased competition among generation sources, coordination with and deference to state regulatory interests, and full recovery of eligible stranded investments.

B. Restructuring the electric power industry is a matter of national interest and priority. Electricity is ubiquitous. Its benefits are key to the American quality of life. Operating 750,000 MW of generation capacity arrayed across three synchronous regional transmission grids, the electric industry is the nation's most capital intensive. The 179 largest investor-owned utilities alone control nearly $600 billion in assets. And, total electricity revenues constitute between 3 and 4 percent of the gross domestic product (GDP)—larger than telecommunications, natural gas pipeline, and airline revenues combined.

Both the Congress and the President have recognized our obligation to ensure that these resources are used wisely and efficiently. We all recognize that systemic change is happening within the industry and that regulation must change to take maximum advantage of the most constructive of those forces. "At the center of the success of our economy is the market, and at the core of the success of the market is competition," states the President in his 1996 Economic Report to the Congress; "it is competition that drives down costs and prices, induces firms to produce the goods consumers want, and spurs innovation and the expansion of new markets abroad." Yet, as state and local governments consider the future of industries heretofore heavily regulated in the public interest, deregulation is not enough, states the President. Competition must be actively promoted and preserved from the abuses and distortions associated with monopoly power, as well as from outdated forms of regulation that provide inappropriate incentives.

In the electric utility restructuring process, several difficult challenges must still be met here and elsewhere. First, policymakers must make the tough choices to attack access discrimination and promote competition while also ensuring reliability and economical service. Success in these undertakings may require pricing innovation and structural reforms to attain significant long-run gains in efficiency and productivity. Economic Report, at 183-185. Second, no transition to a new regime of operating rules and assumptions, can be achieved reasonably if regulated companies are shorn of the opportunity to recover prudently incurred costs. Utility investments that may become stranded or uneconomic as competitive choice displaces franchise monopoly are estimated to represent a $100 billion-plus risk for public utilities. State and federal regulators must confront this issue in the interest of equity and a swift readjustment to the new competitive realities. As the President's Economic Report makes clear, it will be important to future suppliers of private capital for public use that a regulatory bargain made must remain a bargain kept. "Credible government is key to a successful market economy, because it is so important for encouraging long-term investments." Id., at 186-188. Third, maintaining competitive parity and environmental protection are key challenges as well. That means, among other things, that environmental policy must respond to the environmental risks associated with restructuring and vice versa. Id., at 188-189. This assessment of the realities and challenges facing this Commission, its state counterparts, and the diverse elements of the industry substantially ratifies the Commission's actions today.

C. The long-run prospect for reform of the wholesale market is promising, though the task seems daunting. The preamble to the Final Rule begins by outlining the difficult issues that await this Commission and the industry: (1) Corporate organizational matters, including the role of independent system operators (ISOs) in promoting more efficient operation of the transmission system on a regional basis; (2) the need for a new merger policy, which I believe must be predicated on a thorough understanding of emerging markets and genuine ratepayer protections instead of a subjective tally of supposed "benefits"; and (3) further efforts to make greater use of flow-based pricing where appropriate. In adopting the OASIS requirements, we have taken a first step in recognizing that competitive markets do not consist of wires and turbines alone, but of information also. Full competition requires the consolidation of the electron transportation system with the electronic information superhighway.

One thing is abundantly clear: restructuring will require continued innovation and fortitude from our capable staff, cooperation from state regulators, patience and foresight from legislators and, most of all, creativity, responsiveness, and endurance from both utility management and electric consumers.

II. Concurrence on Specific Issues

The Final Rule resolves certain matters of policy and law in ways which, despite my fundamental agreement, I would like to offer some additional perspectives.

A. Coordinating State and Federal Regulatory Interests

Perhaps no single issue will influence the success or failure of restructuring as will the capacity of the FERC and state regulators to reach meaningful accommodations as the electric utility industry becomes increasingly subject to competitive forces. The vertical organization and technological integration of the electric power business contributes to the impression of a regulatory system riddled with gaps and overlaps, interregional inequities, and uncertainty. To the extent that impression predominates in the months to come, the pressure from legislators and the financial community to devise single-minded national solutions to issues of regional or local significance will likely prove irresistible.

The regulation of this industry is a unique exercise in federalism. The Deputy Secretary of Energy wisely acknowledged months ago that, "the aftermath of FERC's open access rulemaking will put to the test our ability to evolve improved means for unsnarling the governance problems of federal and state authorities." Charles B. Curtis, Remarks Before the Third DOE/NARUC National Symposium, December 4, 1995. I find no shortage of good ideas on how to achieve better state, federal, and inter-regional cooperation. But, unanswered questions persist about the availability of sufficient political will and leadership to achieve electricity markets that at once satisfy the need for operational efficiency on a regional level and also provide the "opportunity for experimentation and market testing with the flexibility to comprehend local differences * * * [that is] the very genius of the federal system." Id.

Although it remains unclear today whether this challenge will be met, I firmly believe that the Final Rule is a sound resolution of the jurisdictional questions facing this Commission as a result of competition and open access. State PUC comments reflect enormous concern about the potential loss of jurisdiction over some wires and services, if and when "retail transmission" becomes unbundled. States raise legal objections to our claim of jurisdiction. While reaffirming our view that the Commission has exclusive jurisdiction over the rate, terms, and conditions of interstate transmission, today's order addresses state concerns squarely—first, by adhering to the practical distinctions between transmission and distribution set forth in the NOPR and, second, by according deference[FN1] to states where appropriate when ***21734** retail transmission services become subject to a FERC tariff. These accommodations will smooth the transition to a seamless competitive market with full customer choice, if and when individual states initiate retail competition.

While the Final Rule, not unexpectedly, manifests this Commission's strong interest in preventing balkanization of the interstate power market, nothing adopted by the Commission today, including the interpretation of its authority over retail transmission when retail service is unbundled, is inconsistent with the traditional state roles in developing regulatory, social, and environmental requirements and programs suited to the circumstances of their localities. Section I of the Final Rule is emphatic about this.

I will conclude with two observations on matters I believe to be of particular sensitivity to the states. First, it appears to me that state regulators may impose distribution and other non-bypassable charges or other retail requirements on direct access services, even in those circumstances where no distribution facilities can be identified under the functional/technical test. The Final Rule ensures that result by acknowledging state authority over distribution-related services under the FPA.

Second, state authority is traditionally employed to ensure that power production conforms to local economic, environmental, and resource diversity policy preferences. A state may wish, for example, to ensure that a direct access industrial customer is no less obligated to purchase power consistent with the resource diversity or environmental requirements than is that customer's franchise distribution utility. To the extent that state requirements to own or purchase a certain amount of generation from, say, renewable sources are enshrined in utility supply portfolios, those states have direct influence on the economic and environmental consequences of energy consumption in that jurisdiction. Moreover, such requirements ought to be compatible with open access transmission. However, it will be important that state authority over resource procurement be exercised on a not unduly discriminatory basis. In other words, a PUC may not treat in-state and out-of-state suppliers differently. If access over the network is non-discriminatory in nature, the federal regulatory and constitutional interests are arguably satisfied.

B. Environmental Effects of Restructuring

1. Last July, we instructed our staff to prepare an Environmental Impact Statement (EIS) in conjunction with this rulemaking. The Final EIS (FEIS), issued on April 12, 1996, is an impressive and, with respect to the air impacts of electric restructuring, a pioneering work. It considers in detail: (1) The possible environmental consequences of adopting this Rule, including a number of additional analyses requested by commenters, (2) alternative methods of pursuing open access transmission service, (3) a range of environmental mitigation actions proposed by commenters, and (4) the Commission's legal and technical ability to undertake environmental mitigation. On the whole, I find staff's studies to be analytically sound and generally in conformance with my understanding of this agency's powers to engage in environmental mitigation. Moreover, its conclusions and recommendations are thoughtful and well-reasoned. I therefore believe that consideration of the FEIS as part of the Commission's actions today meets our National Environmental Policy Act of 1969 (NEPA) obligations[FN2] and the requirement of reasoned decisionmaking.

The FEIS highlights a very important public health and social welfare issue, not to mention a matter of great financial importance to certain utilities. To be specific, the FEIS examines potential air quality impacts in the event generation increases from certain coal-fired units. Open transmission access is expected by some to stimulate that additional generation and hence additional nitrogen oxide (NO_X) emissions and related ozone formation. From these projections, a substantive and not altogether constructive debate has ensued. As Section V of the Final Rule describes more fully, the Commission conducted additional studies to respond to comments on the draft EIS, using new recommended baselines for comparison. The results confirm that the air quality impacts of the rule are within reason.

The Commission has satisfied itself that the three most pressing questions have been addressed: (1) What increment of the NO_X emissions problem may be attributable to this Final Rule? (2) Will Final Rule-induced NO_X emission increases be so significant and their impacts sufficiently adverse to justify an alternative regulatory approach, such as "no action" on utility restructuring? (3) Short of no action, can the Commission undertake direct actions that mitigate any potential adverse effects? Based on the FEIS, I can find no justification in the cause, size, or certainty of near-term emissions increases for delaying or diluting the Open Access Rule and no clear basis for a FERC-sponsored emissions control regime, even on an interim basis.

2. Having discharged our NEPA obligations, I cannot pretend that this matter of public interest is no longer of any interest or concern to us. Clean air is a birthright. Air emissions are therefore an important concern. I would not relegate this issue to the periphery of our deliberations. If the EIS process accomplishes nothing else, it has familiarized the FERC with the difficulties of addressing the seemingly intractable problem of NO_X emissions. The problem engenders interregional economic and environmental conflicts that can be addressed only by a sophisticated balancing of interests and a selfless commitment to the greater good. EPA and several commenters on our Rule express frustration over the progress being made to reduce NO_X emissions. For this and other environmental issues, such as NO_X waivers, resort to the courts has become customary, and complex technological and economic disputes are the norm. See e.g., Electric Power Alert, April 24, 1996, at 29-30.

Regions of the country differ, often vehemently, about the source and effects of ozone-causing emissions and how best to curb the generation and transport of pollutants that create ozone. Utilities in some regions have made commitments and invested heavily to achieve "attainment" levels, while the blessings of geography and circumstance have imposed no such burden on others. We recognize in essence that reconciling these interests is a task the Congress has assigned to the EPA. Although the Clean Air Act authorizes EPA to develop a national program to enforce emissions reduction largely through state environmental regulatory efforts (the so-called State Implementation Plans (SIPs)), the statutory process is ponderous in practice. Moreover, even where gains are expected to be made in the form of reduced NO_X emissions (e.g., under EPA's pending rulemaking to set NO_X emissions limitations for certain types of utility boilers), those gains might arguably be offset by future increases in the demand for electricity or, according to some parties, by the additional power generation some say will be encouraged by open access transmission.

The inability to guarantee future NO_X reductions for a variety of reasons that range well beyond this Rule presents formidable challenges. EPA places great faith in the ability of the Ozone Transport Assessment Group (OTAG), a voluntary multi-state organization established in part to set up NO_X emission mitigation mechanism, to address these complex issues and achieve a resolution. It nevertheless appears to me that, for the most part, consensus remains distant. The alternative appears to be an even more protracted EPA procedure.

With respect to the gravamen of this issue (i.e., the establishment of an emissions cap and credit trading system reminiscent of what Congress ordered for sulphur dioxide (SO_2)), this Commission has no real choice but to defer to agencies with jurisdiction by law and special expertise. The EPA has done an outstanding job implementing the market-based SO_2 allowance program. It is widely regarded as both creative and successful. ***21735** OTAG, regardless of any concerns about its processes, brings together a broad range of regional interests, thereby offering an unprecedented opportunity for achieving consensus resolution of this difficult problem.

3. In my view, it behooves this Commission to assist in any way it can, consistent with its expertise and authority, to find consensual solutions. I do not think that means denying polluting utilities access to the transmission system and thereby merely reinforcing their monopoly power. Rather, we must stand ready to assist EPA and OTAG in making competition and environmental responsibility equally attractive. We have begun providing that assistance by ensuring (see II.A. above) that state regulators retain their customary authority under state law to structure the generation and purchase power portfolios of state-regulated utilities. Moreover, the Commission has in the past addressed through its rate jurisdiction various public interest goals, including environmental concerns, intergenerational equities, and least-cost planning needs. For instance, in order to encourage capital investment in pollution control equipment and conservation, the Commission has long allowed utilities to include in rate base the costs of "construction work in progress" (CWIP) for pollution control devices and fuel conversion measures that discourage use of certain fossil fuels.[FN3] In addition, utilities are not eligible for CWIP treatment for plant construction not shown to be the product of integrated resource planning.[FN4]

With respect to the NO_X issue specifically, the Commission is competent to help facilitate an emissions cap and trading system. For instance, the accounting treatment provided for the cost of SO_2 emissions allowances in rates was done to assist implementation of the Clean Air Act.[FN5] The same accommodations could be instituted for a NO_X program. Perhaps the greatest potential for DOE-EPA-OTAG-FERC collaboration and consultation involves our knowledge of the industry and, after preparing the FEIS, our familiarity with the NO_X problem itself. That information should be useful beyond the confines of this rulemaking. In addition, the FEIS indicates (at p. 7-22) that we can structure the electronic bulletin board systems we require so as to facilitate the posting of emissions data required by EPA.

4. Based upon the mutual concerns and the different but complementary expertise of the affected agencies, I encourage the development of consultative mechanisms, memoranda of understanding, or other procedures that will support and help ensure the success of OTAG's efforts. Such efforts must be consistent with the goals and allocation of responsibilities under the Clean

Air Act, and our own regulatory role. Restructuring may pose some environmental risks. We think they are small and (at least eventually) manageable. Further experience is likely to demonstrate that restructuring opens up new possibilities for addressing longstanding environmental problems associated with utility operations. Open access enhances the prospects for environmental dispatch on a statewide or regional basis. It gives isolated renewable plants, particularly hydroelectric and wind power units that are tied to specific geographical features, better market access. I must note that investments in DSM and renewable resources, which offer relatively stable costs, may be an attractive component of utilities' generation portfolios because they also minimize risks. And, as restructuring makes electricity a more customer-driven business, the public's documented preference for environmentally benign power will become more powerful. In addition, efficient markets provide the necessary means to "marketize" environmental rules and perhaps to modify siting and other regulatory processes that are predicated on the vertical integration of the utility sector. And, finally, energy services companies that can promote conservation and generation alternatives require more open and dynamic markets. For the environment, the prospects offered by restructuring are exciting. Inhibiting or stopping its development will not help it.

III. Partial Dissent

The Final Rule announces that the Commission will be the "primary forum" to hear stranded cost claims where a retail power customer turns wholesale wheeling customer, usually through a municipalization (Situation 2). Although the Final Rule recognizes that states do have authority to deal with stranded costs in Situation 2, the majority nevertheless instructs parties to bring their claims to this Commission "in the first instance." However, where costs are stranded due to state authorized retail wheeling (Situation 3), the majority takes a different and, I contend, incongruent approach that effectively denies any forum for those costs if state regulators possess authority to act but do not do so. Because I find nothing in policy or law to commend this approach, I respectfully dissent.[FN6]

I take issue with the "primary forum" approach because I believe that it: (1) Requires the Commission to second-guess state determinations on recovery of costs incurred at retail at a time when many states are addressing the issue; (2) will encourage forum shopping; and (3) is inconsistent with our approach in the retail wheeling situation; and (4) involves an unnecessary legal risk for the Commission.

A. Second-Guessing State Determinations of Retail Stranded Costs is Unwise and Unnecessary

The Final Rule's stranded cost recovery methodologies and the underlying jurisdictional assumptions are aimed at achieving full recovery of all legitimate, verifiable and prudent stranded costs, consistent with a utility's reasonable expectations and the justness and reasonableness of the underlying contract. I believe that this is a worthy objective, but it is not one which requires the Commission to second-guess state determinations. As state proceedings now reveal, the Commission's leadership in raising this issue has borne fruit. Where municipalization is occurring, states are addressing stranded costs responsibly. In nearby Virginia, for example, the Virginia State Corporation Commission has interceded into the dispute between Virginia Electric Power Company and the City of Falls Church over the City's plans to undertake a "muni-lite" form of municipalization. Moreover, the record before us today does not endorse the view that municipalization constitutes a major bypass threat to stranded cost recovery.

Notwithstanding such developments, the Final Rule announces that the Commission will be the "primary forum" to hear stranded cost claims where a retail power customer turns wholesale wheeling customer, usually through a municipalization. While declaration of "primary forum" status sounds very legalistic, there is in fact no legal basis for it. The policy is not founded on a concept of federal preemption in the area. Indeed, the Federal Power Act provides no basis for preemption. Moreover, the Final Rule recognizes that states do have authority to deal with stranded costs in these circumstances. The majority's instruction to bring claims directly to FERC will, if anything, afford states a reason to avoid this difficult issue altogether.

B. The "Primary Forum" Approach May Encourage Forum Shopping

As a policy matter, the majority's approach is peculiar on its face. Although the "primary forum" approach is intended to eliminate forum shopping, it will not achieve even that objective. Indeed, I think the "primary forum" approach may encourage parties to forum shop. State commissions or legislatures will often provide for stranded cost recovery at the time the wholesale entity is formed. Similarly, condemnation proceedings may provide for stranded costs in whole or part. Moreover, standards for stranded cost recovery are occasionally prescribed by statute. In reality, the Commission cannot preclude the states from acting on stranded cost issues and our proposed rule may encourage rather than discourage forum shopping.

C. The "Primary Forum" Approach Covers Fact Situations Largely Indistinguishable From the Retail Wheeling Scenario

The majority's decision to take primary jurisdiction of costs where a retail power customer becomes wholesale wheeling customer through municipalization and to distance itself from virtually any cost recovery responsibility where retail power customers becomes retail wheeling customers does not withstand scrutiny. These are not factually distinguishable cases, insofar as jurisdiction over stranded costs is concerned. The inadequacy of the majority's reasoning is palpable because it has adopted very different policies with respect to two stranded cost situations that, if properly understood, are virtually indistinguishable.

***21736** First, in both Situations 2 and 3, retail power costs are stranded by customers who gain access to FERC jurisdictional transmission tariffs via state action. In Situation 2, state municipalization law governs. In Situation 3, the state has authorized retail wheeling by statute or regulation, or both. Notwithstanding the need for state authorization in both cases, the majority decides that the Commission should be the "primary forum" in Situation 2, but that a much more narrow approach to retail stranded costs in Situation 3.[FN7] The more aggressive "primary forum" approach to municipalization is predicated on the view that any strandings are a result of an inducement (i.e., market options) created by this Commission's Open Access Rule. Yet, since both wholesale transmission customers and retail transmission customers are "eligible customers" under the tariffs required by this Rule, if the Rule induces the stranding of retail power costs in one situation, it obviously does it in both.

As commenters have noted, the relationship between FERC-regulated transmission service and retail power customers is generally the same in both Situations 2 and 3.[FN8] The similarity runs first to the actions that actually cause costs to be stranded. While it is true that retail wheeling will only occur pursuant to state legislative or regulatory action, it is also true that a retail customer can only convert to wholesale status (e.g., municipalize) pursuant to state law. This process sometimes may occur in the absence of regulatory or other oversight (e.g., municipalization under pre-established statutory scheme), or with direct and immediate review and approval. The current evidence reflects active state commission oversight, typically. In this latter case, there is even less reason to distinguish between these Situations.

The majority implicitly seeks to delimit the area of appropriate state authority over stranded costs according to whether the state acts directly and by current enactments to authorize retail wheeling, on one hand, or less directly through established state municipalization laws, on the other. However, costs could be stranded under state law by either action. Under the former scenario, however, a state is presumed to be more willing and capable of dealing with stranded costs. Under the latter, it is presupposed to be less interested. This distinction is specious.

A second similarity pertains to the jurisdictional status of transmission service. The Commission has been clear and consistent that the FPA gives the Commission exclusive jurisdiction over interstate transmission service, regardless of whether the customer is a wholesale or a retail wheeling customer. It is this authority upon which we rely to claim jurisdiction over transmission assets and related costs originally incurred to provide customers at the retail level with bundled service. New wheeling customers in both Situations 2 and 3 will take service under FERC open access tariffs. There are identical cost-causational facts in Situations 2 and 3, yet the majority adopts very different outcomes in each case under the Final Rule.

D. The "Primary Forum" Approach is More Subject to Legal Challenge

In my view, our disagreement involves more than a policy choice. The majority's chosen approach clearly makes our stranded cost recovery approach more vulnerable to a legal challenge. The cost recovery scheme which would result from the majority's approach will render a FERC-ordered transmission surcharge to recover retail stranded costs susceptible to legal challenge on the basis that it is anti-competitive and unduly discriminatory. The "primary forum" approach imposes upon a retail-turned-wholesale customer something akin to double jeopardy. In other words, a departing customer might have to pay both an exit fee for the retail costs which the state commission finds it has stranded and, in addition, an entry fee for wholesale access in the amount of the additional retail stranded costs which FERC determines are inadequately covered by state proceedings.

This, in my view, makes the Final Rule more susceptible to challenges that FERC's transmission surcharge is anti-competitive. E.g., Cajun Electric Power Cooperative, Inc. v. FERC, 28 F.3d 173 (D.C. Cir. 1994). The second-guessing of states inherent in the "primary forum" approach makes any arguments that stranded cost recovery is anti-competitive more difficult to overcome than if the stranded costs resulted from wholesale customers simply changing wholesale suppliers. This is because, unlike wholesale-to-wholesale strandings, the Commission cannot plausibly argue that the costs incurred were originally addressed in the context of its own rate decisions or were previously part of its responsibility for administering wholesale service obligations.

I am strongly persuaded that the Commission would be on much stronger legal ground if we were to treat state authority over stranded costs with the same deference in the municipalization or "retail-turned-wholesale" situation in the same manner as the Final Rule prescribes for situations where retail wheeling occurs. In the latter case, the Commission ought to provide a forum where neither the state legislature nor the state commission attempts to address this important transition issue.

James J. Hoecker,

Commissioner.

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities

Recovery of Stranded Costs by Public Utilities and Transmitting Utilities

[Docket No. RM95-8-000; Docket No. RM94-7-001]

Issued April 24, 1996.
MASSEY, Commissioner, dissenting in part:

I support all of the provisions of this rule save one, the provision on stranded costs arising from retail competition and from municipalization. When the Commission issued the Notice of Proposed Rulemaking, I stated that the Commission should treat stranded costs arising from retail competition and municipalizations similarly, as follows:

For either retail competition or municipalization, when the state commission has authority to address the issue, and uses such authority to decide the recoverability of the stranded costs, the state's decision should not be second-guessed by this Commission. However, when a state commission does not have the authority to decide the recoverability of stranded costs, or has authority but does not use it, this Commission should act on requests for stranded cost recovery.

My approach would assure utilities of getting a decision on the merits of their claim. Costs would not be stranded for lack of a regulatory decision. At the same time, this Commission would allow states to make decisions, when they have authority, on issues of critical concern to their local utilities and ratepayers. Only if states lack, or fail to use, such authority would this Commission step in to assure the utility of receiving a decision on the merits.

For the reasons I stated then, I still disagree with the rule's approach to stranded costs arising from retail competition or municipalization. In all other respects, I support this rule.

William L. Massey,

Commissioner.

[FR Doc. 96-10694 Filed 5-9-96; 8:45 am]

BILLING CODE 6717-01-P

Footnotes

1 These rules are the rules on open access and stranded costs in the above dockets (FERC Stats. & Regs. 31,036), and an accompanying rule on Open Access Same-Time Information System and Standards of Conduct (OASIS Final Rule) (FERC Stats. & Regs. 31,037) being issued contemporaneously. The Commission also is issuing contemporaneously a notice of proposed rulemaking on capacity reservation open access transmission tariffs in Docket No. RM96-11-000, FERC Stats. & Regs. 32,517. These final rules and proposed rule are being published concurrently in the Federal Register.

2 On March 29, 1995, the Commission issued two notices of proposed rulemaking concerning open access transmission and stranded cost recovery. Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking. 60 FR 17662 (April 7, 1995), FERC Stats. & Regs. 32,514 (1995). On December 13, 1995, the Commission issued a notice of proposed rulemaking on information systems. Real-Time Information Networks and Standards of Conduct, Notice of Proposed Rulemaking. 60 FR 66182 (December 21, 1995), FERC Stats. & Regs. 32,516 (1995).

FN3 The Commission's notice of proposed rulemaking in the above dockets proposed to apply the proposed requirements to public utilities that own and/or control facilities used for the transmission of electric energy in interstate commerce. "Own and/or control" is intended to include public utilities that "operate" facilities used for the transmission of electric energy in interstate commerce. However, we have modified the Final Rule regulatory text to remove any ambiguity.

4 42 U.S.C. 7401, et seq.

5 42 U.S.C.A. 7651b-e.

6 Paul L. Joskow, Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation, 17 J. Law & Econ. 291, 312 (1974); see also Charles F. Phillips, Jr., The Regulation of Public Utilities 11 (1988).

FN7 See Joskow, supra at 312; see also Phillips, supra at 12.

8 See Joskow, supra at 312; see also Phillips, supra at 12-13.

FN9 See Joskow, supra at 312-13; see also Phillips, supra at 13. The Arab oil embargo resulted in significantly higher oil prices through the 1970s. See Richard J. Pierce, Jr., The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity, 132 U. Pa. L. Rev. 497, 501 (1984).

FN10 See Joskow, supra at 313; see also Phillips, supra at 13.

11 See generally Jersey Central Power & Light Company v. FERC. 810 F.2d 1168, 1171 (D.C. Cir. 1987).

FN12 Id.

FN13 See Pierce, supra at 503. By 1983, the Department of Energy had estimated that the sunk costs for canceled nuclear plants alone amounted to $10 billion. Id. at 498.

FN14 Id.

FN15 See Bernard S. Black & Richard J. Pierce, Jr., The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry, 93 Col. L. Rev. 1339, 1346 (1993) ("Actual costs of nuclear power plants vastly exceeded estimates, sometimes by as much as 1000%.").

FN16 See Phillips, supra at 13. Fossil fuel-fired plants became subject to increased regulation as a result of the Clean Air Act of 1970, and its 1977 amendments. 42 U.S.C. 7401-7642. In 1971, nuclear plant licensing became subject to the environmental impact statement requirements of the National Environmental Policy Act of 1969. 42 U.S.C. 4332. Following the 1979 accident at the Three Mile Island nuclear plant, nuclear plants also became subject to additional safety regulations, resulting in higher costs. See Energy Information Administration, The Changing Structure of the Electric Power Industry 1970-1991 (March 1993) 35. Between 1976 and 1980, most states and many localities instituted laws governing power plant siting.

17 Based on retail prices reported in Energy Information Administration (EIA), Monthly Energy Review, January 1995, Table 9.9 (Prices adjusted for inflation using the GDP Deflator (1987 = 100)).

FN18 Id.

19 See Black & Pierce, supra at 1346 (These writeoffs were "about 17% of the book value of total 1992 utility investment.").

FN20 Id.

FN21 Id. ("The high perceived risk of future disallowances reversed utilities' incentives to overinvest, and made utilities extremely reluctant to build new power plants.").

22 See Preston Michie, Billing Credits for Conservation, Renewable, and Other Electric Power Resources: an Alternative to Marginal-Cost-Based Power Rates in the Pacific Northwest. 13 Environmental Law 963, 964-65 (1983).

FN23 Id. at 965.

FN24 Energy Information Administration, The Changing Structure of the Electric Power Industry 1970-1991 (March 1993) 37 ("As larger units were constructed, however, utilities discovered that downtime was as much as 5 times greater for units larger than 600 megawatts than for units in the 100-megawatt range.")

FN25 Id.; see also George A. Perrault, Downsizing Generation: Utility Plans for the 1990s, Pub. Util. Fort. 15-16 (Sept. 27, 1990) ("The large base-load generating units that form the backbone of utility systems are almost totally absent from capacity plans for the 1990s.").

26 "From 1982 through 1991, the average capacity of fluidized-bed units increased rapidly to 72 megawatts for 4 units in 1991. The average capacity for the 19 units planned to begin operating in 1992 through 1995 increases to 83 megawatts." Energy Information Administration, The Changing Structure of the Electric Power Industry 1970-1991 (March 1993) 38.

27 See Charles E. Bayless, Less is More: Why Gas Turbines Will Transform Electric Utilities, Pub. Util. Fort. (Dec. 1, 1994) 21.

28 Id. at 24. See also Wallace E. Brand, Is Bigger Better? Market Power in Bulk Power Supply: From FDR to NOPR, Pub. Util. Fort. (Feb. 15, 1996) 23 at 25 (while the optimal baseload unit size is about 500 MW for coal-fired steam turbines, the optimal size for gas fired combined-cycle units is about 150 to 200 MW).

FN29 FERC staff calculations based in part on combined-cycle plant cost data reported in 1994 FERC Form No. 1 for a sample of units placed in service during 1990-94. Costs vary with regional fuel and construction costs, among other reasons.

FN30 Coal and Nuclear plant cost data reported in 1994 FERC Form No. 1 and the EIA report, Electric Plant Cost and Power Production Expenses 1991, 1993 DOE/EIA-0455(91), for plants placed in service during 1986-94; see also The 1994 Electric Executives' Forum, Bakke (President and CEO of the AES Corporation), Pub. Util. Fort. (June 1, 1994) 45 ("New generation can be built at about 3 cents per kilowatt-hour (U.S. average). Old generation costs about twice that * * *").

FN31 See Black & Pierce, supra at 1345 (In the late 1960s and 1970s, improved transmission efficiency and development of regional transmission networks "made it possible to build power plants up to 1000 miles from power users.").

FN32 Coordination transactions are voluntary sales or exchanges of specialized electricity services that allow buyers to realize cost savings or reliability gains that are not attainable if they rely solely on their own resources. For sellers, these transactions provide opportunities to earn additional revenue, and to lower customer rates, from capacity that is temporarily excess to native load capacity requirements.

33 Pub. L. No. 95-617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

FN34 See generally FERC v. Mississippi, 456 U.S. 742, 745-46 (1982).

FN35 The Power Plant and Industrial Fuel Use Act of 1978. Pub. L. No. 95-617, 92 Stat. 3117 (codified in U.S.C. sections 15, 16, 26, 30, 42, and 43).

FN36 QFs include certain cogenerators and small power producers. PURPA also added sections 210, 211, and 212 to the FPA, providing the Commission with authority to approve applications for interconnections and, in limited circumstances, wheeling. However, under section 211, as enacted in PURPA, the Commission could approve an application for wheeling only if it found, inter alia, that the order "would reasonably preserve existing competitive relationships." Because of this and other limitations in sections 211 and 212 as originally enacted, the provision was virtually ineffective. Only one section 211 order was ever issued pursuant to the original provision, and it was pursuant to a settlement. See Public Service Company of Oklahoma, 38 FERC 61,050 (1987). As discussed infra, section 211 was subsequently revised by the Energy Policy Act of 1992.

FN37 456 U.S. at 750. Congress recognized that encouragement was needed in part because utilities had been reluctant to purchase electric power from, and sell power to, nonutility generators. Id. at 750-51.

38 For example, PURPA provided that a cogeneration facility or small power production facility could not be owned by a person primarily engaged in the generation or sale of electric power (other than from cogeneration or small power production facilities). See 16 U.S.C.

FN39 Energy Information Administration, Electric Power Annual 1993 (December 1994) 124 (Table 77).

FN40 Id. EIA data for 1989 through 1991 was for facilities of 5 megawatts or more and for 1992 and 1993 was for facilities of 1 megawatt or more. A comparison with Table 74 on page 121 for the years 1992 and 1993 reveals that this mixing of data bases is likely of minimal effect.

41 Generally, the law has imposed an 80 MW cap on small power producers. A limited exception enacted in 1990 permitted small power facilities that could exceed 80 MW and still qualify as QFs under PURPA. This exception was limited to certain solar, wind, waste, and geothermal small power production facilities and only covered applications for certification of facilities as qualifying small power production facilities that were submitted no later than December 31, 1994 and for which construction commences no later than December 31, 1999. See Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990, Pub. L. No. 101-575, 104 Stat. 2834 (1990), amended, Pub. L. No. 102-46, 105 Stat. 249 (1991).

42 The first power marketer in the electric industry was Citizens Energy Corporation. See Citizens Energy Corporation, 35 FERC 61,198 (1986). Power marketers take title to electric energy. Power brokers, on the other hand, do not take title and are limited to a matchmaking role.

43 15 U.S.C. 79 et seq.

FN44 As discussed infra, Congress eventually provided a means to avoid the PUHCA restrictions by creating exempt wholesale generators (EWGs) in the Energy Policy Act.

45 The industry was successful to some extent in developing ownership structures that permitted such investment. See, e.g., Commonwealth Atlantic Limited Partnership, 51 FERC 61,368 at 62,240 and n.20 (1990).

FN46 Energy Information Administration, Electric Power Annual 1993 (December 1994) 124 (Table 77).

FN47 Black & Pierce, supra at 1349 n.25.

48 See, e.g., Ocean State Power, 44 FERC 61,261 (1988); Commonwealth Atlantic Limited Partnership, 51 FERC 61,368 (1990); Citizens Power & Light Company, 48 FERC 61,210 (1989); Orange and Rockland Utilities, Inc., 42 FERC 61,012 (1988); Doswell Limited Partnership, 50 FERC 61,251 (1990) (Doswel); and Dartmouth Power Associates Limited Partnership, 53 FERC 61,117 (1990).

FN49 See, e.g., Doswell, 50 FERC at 61,757.

50 Citizens Power & Light Corporation, 48 FERC 61,210 at 61,777 (1989) (emphasis in original); see also Utah Power & Light Company, PacifiCorp and PC/UP&L Merging Corporation, 45 FERC 61,095 at 61,287-89 (1988), order on reh'g, 47 FERC 61,209, order on reh'g, 48 FERC 61,035 (1989), remanded in part sub nom. Environmental Action, Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991), order on remand, 57 FERC 61,363 (1991).

51 In earlier years, a few customers were able to obtain access as a result of litigation, beginning with the Supreme Court's decision in Otter Tail Power Company v. United States, 410 U.S. 366 (1973). Additionally, some customers gained access by virtue of Nuclear Regulatory Commission license conditions and voluntary preference power transmission arrangements associated with federal power marketing agencies. See, e.g., Consumers Power Company, 6 NRC 887, 1036-44 (1977) and The Toledo Edison Company and Cleveland Electric Illuminating Company, 10 NRC 265, 327-34 (1979). See Florida Municipal Power Agency v. Florida Power and Light Company, 839 F. Supp. 1563 (M.D. Fla. 1993). See also Electricity Transmission: Realities, Theory and Policy Alternatives, The Transmission Task Force Report to the Commission, October 1989, 197.

FN52 See, e.g., Public Service Company of Colorado, 59 FERC 61,311 (1992), reh'g denied, 62 FERC 61,013 (1993); Utah Power & Light Company, et al., Opinion No. 318, 45 FERC 61,095 (1988), order on reh'g, Opinion No. 318-A, 47 FERC 61,209 (1989), order on reh'g, Opinion No. 318-B, 48 FERC 61,035 (1989), aff'd in relevant part sub nom. Environmental Action Inc. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991); Northeast Utilities Service Company (Public Service Company of New Hampshire), Opinion No. 364-A, 58 FERC 61,070, reh'g denied, Opinion No. 364-B, 59 FERC 61,042, order granting motion to vacate and dismissing request for rehearing, 59 FERC 61,089 (1992), affirmed in relevant part sub nom. Northeast Utilities Service Company v. FERC, 993 F.2d 937 (1st Cir. 1993).

FN53 See, e.g., Public Service of Indiana, Inc., 51 FERC 61,367 (1990), reh'g denied, 52 FERC 61,260 (1990), appeal dismissed sub nom. Northern Indiana Public Service Company v. FERC, 954 F.2d 736 (D.C.Cir. 1992).

54 Pub. L. No. 102-486, 106 Stat. 2776 (1992), codified at, among other places, 15 U.S.C. 79z-5a and 16 U.S.C. 796 (22-25), 824j-l.

FN55 See El Paso Electric Company and Central and South West Services Inc., 68 FERC 61,181 at 61,914 (1994) (CSW); see also Paul Kemezis, FERC's Competitive Muscle: The Comparability Standard, Electrical World 45 (Jan. 1995) ("In EPAct, Congress made it clear that the electric-power industry was to move toward a fully competitive market system, but left most of the implementation to FERC.").

56 15 U.S.C. 79z-5a.

57 15 U.S.C. 79z-5a(e).

58 See supra note 36.

59 See Policy Statement Regarding Good Faith Requests for Transmission Services and Responses by Transmitting Utilities Under Sections 211(a) and 213(a) of the Federal Power Act, as Amended and Added by the Energy Policy Act of 1992, 58 FR 38964 (July 21, 1993), FERC Stats. & Regs., Regulations Preambles 30,975 (1993) (Policy Statement Regarding Good Faith Requests for Transmission Services).

FN60 See New Reporting Requirements Implementing Section 213(b) of the Federal Power Act and Supporting Expanded Regulatory Responsibilities Under the Energy Policy Act of 1992, and Conforming and Other Changes to Form No. FERC-714, 58 FR 52420 (October 8, 1993), FERC Stats. & Regs., Regulations Preambles 30,980 (Order No. 558), reh'g denied, Order No. 558-A, 65 FERC 61,324 (1993), regulations modified, 59 FR 15333 (April 1, 1994), FERC Stats. & Regs., Regulations Preambles 30,993.

61 See Order No. 550, Filing Requirements and Ministerial Procedures for Persons Seeking Exempt Wholesale Generator Status, 58 FR 8897 (February 18, 1993), FERC Stats. & Regs., Regulations Preambles 30,964, order on reh'g, Order No. 550-A, 58 FR 21250 (April 20, 1993), FERC Stats. & Regs., Regulations Preambles 30,969 (1993). As recognized by Congress and the Commission, availability of transmission information is critical in developing competitive markets. See supra notes 59 and 60. This opened the "black box" of information that previously was available only to transmission owners.

62 See Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, 59 FR 35274 (July 11, 1994), FERC Stats. & Regs., Proposed Regulations 32,507 at 32,866 (Stranded Cost NOPR); American Electric Power Service Corporation, 67 FERC 61,168, clarified, 67 FERC 61,317 (1994).

63 16 U.S.C.A. 824j-824k (West 1985 and Supp. 1994).

FN64 See, e.g., final orders issued in City of Bedford, 68 FERC 61,003 (1994), reh'g denied, 73 FERC 61,322 (1995); Florida Municipal Power Agency v. Florida Power & Light Company, 67 FERC 61,167 (1994), order on reh'g, 74 FERC 61,006 (1996); Minnesota Municipal Power Agency, 68 FERC 61,060 (1994); and Tex-La Electric Cooperative of Texas, 69 FERC 61,269 (1994); see also Appendix A.

65 See Florida Municipal Power Agency v. Florida Power & Light Company, 65 FERC 61,125, reh'g dismissed, 65 FERC 61,372 (1993), final order, 67 FERC 61,167 (1994), order on reh'g, 74 FERC 61,006 (1996). The Commission has "characterized point-to-point service as involving designated points of entry into and exit from the transmitting utility's system, with a designated amount of transfer capability at each point." El Paso Electric Company v. Southwestern Public Service Company, 68 FERC 61,182 at 61,926 n.9 (1994) (citing Entergy Services, Inc., 58 FERC 61,234 at 61,768 (1993), reh'g dismissed, 68 FERC 61,399 (1994)). Network service allows more flexibility by allowing a transmission customer to use the entire transmission network to provide generation service for specified resources and specified loads without having to pay multiple charges for each resource-load pairing.

FN66 Florida Municipal, 67 FERC at 61,477.

67 69 FERC 61,035 at 61,165 (1994), reh'g denied, 72 FERC 61,071 (1995); see also Southwest Regional Transmission Association, 69 FERC 61,100 at 61,398 (1994), order on compliance filing, 73 FERC 61,147 (1995) (SWRTA).

68 64 FERC 61,279 (1993), reh'g granted, 67 FERC 61,168, clarified, 67 FERC 61,317 (1994).

FN69 The Commission explained that AEP could limit the service it was offering because it was "providing the service voluntarily under a tariff of general applicability." 64 FERC at 62,978.

FN70 AEP, 67 FERC at 61,489.

71 With respect to anticompetitive effects, the Commission explained that it has "adhered to the Supreme Court's determination that the Commission's 'important and broad regulatory power * * * carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to sections 202 and 203, and under like directives contained in sections 205, 206 and 207.' Gulf States Utilities Company v. FPC, 411 U.S. 747, 758-59 (1972)." Id. at 61,490 (footnote omitted). The Commission reaffirmed that it would examine how best to fulfill this responsibility, as well as its responsibility to prevent undue discrimination, in light of the changing conditions in the electric utility industry. Id.

72 Id. at 61,490.

73 Id. at 61,490-91.

74 See Kansas City Power & Light Company, 67 FERC 61,183 (1994), reh'g pending.

75 E.g., CSW, supra, 68 FERC at 61,914.

FN76 Id.

77 Id. at 61,915 (footnote omitted).

78 68 FERC 61,223 (1994).

79 Id. at 62,060. In InterCoast Power Marketing Company, 68 FERC 61,248, clarified, 68 FERC 61,324 (1994), the Commission rejected an affiliated marketer's proposal to sell at market rates without its affiliate utility offering comparable transmission services. The Commission stated that the only way to ensure that InterCoast does not have transmission market power is to require its affiliated public utility to offer comparable transmission services. See also LG&E Power Marketing Inc., 68 FERC 61,247 at 62,120-21 (1994). The Commission added that this is consistent with encouraging competitive bulk power markets as envisioned by the Energy Policy Act of 1992. Id. at 62,132.

80 See Hermiston Generating Company, 69 FERC 61,035 at 61,164 (1994), reh'g pending. The Commission subsequently accepted the rates on a cost basis. See Letter Order dated November 10, 1994.

81 Id. at 61,165.

82 See SWRTA, 69 FERC at 61,397; see also PacifiCorp, the California Municipal Utilities Association, and the Independent Energy Producers (on behalf of Western Regional Transmission Association), 69 FERC 61,099, order on reh'g, 69 FERC 61,352 (1994), order on compliance filing, 71 FERC 61,158 (1995) (WRTA). An RTG is a regional transmission group. It is defined as "a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and inter-regional." Policy Statement Regarding Regional Transmission Groups, 58 FR 41626 (August 5, 1993), FERC Stats. & Regs., Regulations Preambles 30,976 at 30,870 n. 4 (RTG Policy Statement).

83 SWRTA, 69 FERC at 61,398.

84 KCP&L, 67 FERC 61,183 (1994).

85 Id. at 61,557 (citing Entergy Services, Inc., 58 FERC 61,234 at 61,756 and nn. 63 and 65 (Entergy)).

86 Id. The Commission added that "after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets." Id.

FN87 Id.

88 FERC Stats. & Regs. 32,507 (1994).

FN89 Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 FR 55031 (November 3, 1994), FERC Stats. & Regs., Regulations Preambles 31,005 (Transmission Pricing Policy Statement).

FN90 Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, 59 FR 54851 (October 26, 1994), FERC Stats. & Regs., Notices 35,529 (1995) (Pooling Notice of Inquiry).

FN91 FERC Stats. & Regs. 30,976 (RTG Policy Statement).

FN92 FERC Stats. & Regs. 35,531 (1996).

93 FERC Stats. & Regs. 32,507 at 32,864.

94 Most transmission contracts set a single price for energy flow over a utility's transmission system. This single-price policy is called "postage stamp" pricing because the rate does not depend on how far the power moves within a company's transmission system. If power flows through several companies, traditional industry practice is to specify that power flows along a "contract path" consisting of the transmission-owning utilities between the ultimate receipt and delivery points. See Indiana Michigan Power Company, 64 FERC 61,184 at 62,545 (1993).

FN95 Unlike with postage stamp pricing, with distance-sensitive pricing the cost of moving power through a company depends on how far the power moves within the company. In contrast to contract path pricing, flow-based pricing establishes a price based on the costs of the various parallel paths actually used when the power flows. Because flow-based pricing can account for all parallel paths used by the transaction, all transmission owners with facilities on any of the parallel paths could be compensated for the transaction.

FN96 FERC Stats. & Regs. 31,005 at 31,136.

FN97 Id. at 31,142.

98 FERC Stats. & Regs. 35,529 at 35,715.

99 Id. at 35,714. As explained below, the Commission held technical conferences on issues surrounding power pools and competition.

100 See WRTA and SWRTA, supra, and Northwest Regional Transmission Association, 71 FERC 61,397 (1995).

101 At least 12 states have retail wheeling proposals, legislation, or pilot programs underway—Alabama, California, Connecticut, Illinois, Massachusetts, Michigan, New Hampshire, New York, Ohio, Rhode Island, Vermont, and Wisconsin. At least 14 other states are investigating retail wheeling. Currently, according

to a report of the NARUC-affiliated National Council on competition and the Electric Industry, 41 States are actively involved in investigating whether and how to restructure their respective electric power markets. Of this total, 29 State regulatory authorities * * * have initiated investigations. In addition, five State legislatures are involved in similar investigations, while seven other States have joint regulatory/legislative proceedings underway.

Testimony of the Honorable Cheryl L. Parrino, Chair of the Wisconsin Public Service Commission, on behalf of the National Association of Regulatory Utility Commissioners, before the United States Senate Committee on Energy and Natural Resources (March 6, 1996).

102 See American Electric Power Service Corporation, et al., 72 FERC 61,287 at 61,238 (1995).

103 Attached to this Final Rule as Appendix B is a list of commenters and the abbreviations used to designate them, including those commenters that filed late.

104 Energy Information Administration, Performance Issues for a Changing Electric Power Industry (January 1995) 10 and (Figure 5).

FN105 Current Competition, November 1994, Vol. 5, No. 8, at 8.

106 As discussed above, a significant number of public utilities still do not have any form of an "open access" tariff on file with the Commission and no public utility has on file a non-discriminatory open access tariff as defined by this Rule.

107 FERC Stats. & Regs. 32,514 at 33,080.

108 E.g., Ohio Edison, UtiliCorp, Pennsylvania P&L, Atlantic City, Montana Power, IL Com, Seattle, OK Com, TX Industrials, MidAmerican, Southwestern, Southern, DOD, Public Service Co of CO, SC Public Service Authority, Florida Power Corp, DOE, WP&L, Com Ed, SBA, Consumers Power, CA Com, UT Com, Houston L&P, KCPL, EEI.

FN109 E.g., Florida Power Corp, El Paso, PSNM, and SC Public Service Authority.

110 E.g., Southwestern, PECO, El Paso, Florida Power Corp, NSP, Public Service E&G, MidAmerican.

111 E.g., NRECA, IN Com, Power Marketing Association, TDU Systems, NorAm, Turlock, Texaco, Utility Shareholders, NSP, El Paso, Utility Investors Analysts, PECO, Florida Power Corp, UT Com, Sierra, Carolina P&L, SoCal Gas, OK Com, FL Com, Southern.

112 E.g., American Forest & Power, American National Power, ND Com, IL Com, UAMPS, NIEP, APPA, Public Power Council, Municipal Energy Agency Nebraska, Missouri Basin MPA, Texaco, Direct Services Industries, Calpine, CCEM, Wisconsin Coalition, VT DPS.

FN113 See also American National Power, ND Com, Calpine.

114 NIEP Initial Comments at 4.

115 See also Municipal Energy Agency Nebraska, Direct Services Industries.

116 Others oppose operational unbundling. See, e.g., Carolina P&L, Salt River.

117 When and how functional unbundling is to be achieved for requirements transactions and for various types of coordination arrangements, including power pools, is discussed at Sections IV.A.5 and IV.F. Functional unbundling of ancillary services is discussed in Section IV.D.

118 Real-Time Information Networks and Standards of Conduct, Notice of Proposed Rulemaking, 60 FR 66182 (December 21, 1995), FERC Stats. & Regs., Proposed Regulations 32,516 at 33,170 (1995).

119 The final rule on information systems no longer uses the terminology RINs. The new terminology used is OASIS—Open Access Same-time Information System—which we will use in this Final Rule.

120 67 FERC 61,183 at 61,557 (1994), reh'g pending (KCP&L).

FN121 FERC Stats. & Regs. 32,514 at 33,050.

122 Id. at 33,154.

123 67 FERC at 61,557.

124 E.g., Entergy, EEI, Atlantic City, Duke Centerior, Houston L&P, Montana-Dakota Utilities, Canadian Petroleum Producers, DOE, Florida Power Corp, PSNM.

FN125 E.g., EEI, Centerior, Houston L&P, NYSEG.

126 E.g., TDU Systems, ELCON, NRECA, Environmental Action, NIEP, APPA, Power Marketing Association, EGA.

127 See, e.g., MidAmerican Energy Company, 74 FERC 61,211 (1996).

128 KCP&L, 67 FERC at 61,557. See also discussion in proposed rule, FERC Stats. & Regs. at 33,067-68

FN129 Id.

FN130 The NOPR's proposed language that a public utility would not have to demonstrate a lack of market power in generation for sales from capacity first placed in service on or after the date 30 days after the final rule is published in the Federal Register does not properly reflect the finding in KCP&L. Because KCP&L addressed new or unbuilt generation, the proposed language is being revised as indicated above and as set forth in the regulatory text included with this Final Rule.

131 Cf. Wisconsin Electric Power Company, et al., 74 FERC 61,069 at 61,193 (1996).

132 FERC Stats. & Regs. 32,514 at 33,093-94.

133 E.g., EEI, CINergy, Central Illinois Public Service, Citizens Utilities, Com Ed, Ohio Edison, Allegheny, Southern, Portland, NRRI, Pennsylvania P&L, PECO, Dayton P&L, Utilities For Improved Transition, Centerior, Houston L&P, Duke, ConEd, IPALCO, Salt River, PJM, NU, NYSEG, Oklahoma G&E, PA Com, OK Com, CT DPUC, CA Com, MT Com.

134 E.g., Consumers Power, Portland, Dayton P&L, CSW.

135 See also Citizens Utilities.

136 See also CSW, Industrial Energy Applications, Public Service Co of CO, Coalition for Economic Competition.

137 E.g., NRECA, TDU Systems, MT Com, SMUD, NEPCO, Orange & Rockland, El Paso, American Forest & Paper, NIPSCO, AEC & SMEPA, OH Com, IL Com, IN Com, Legal Environmental Assistance, LG&E, Cajun, Industrial Energy Applications, LEPA, MA DPU, MI Com, FTC, Minnesota P&L, SC Public Service Authority, WP&L, NARUC, Canadian Petroleum Producers, DOD, CCEM, Environmental Action, American Wind, Cajun, NIEP, EGA, TAPS, ELCON, Consolidated Natural Gas.

FN138 See also NIEP, Pacificorp, CA Energy Com.

FN139 See also MT Com, TDU Systems, Soyland.

FN140 See also AEC & SMEPA, NIPSCO, El Paso (discusses a particular transmission constraint that it states limits its access to suppliers).

NRECA is also concerned that mergers may create a handful of "mega-public utilities" that may affect a regional generation market and that the Commission should apply more traditional antitrust principles in analyzing the impacts of mergers.

141 LEPA Initial Comments Affidavit of William G. Shepherd at 4.

FN142 See also DOD and WP&L IL Com suggests that the Commission allow market-based rates to a utility on the condition that the utility forego stranded cost recovery.

143 NEPOOL Review Committee Initial Comments at 28.

144 See, e.g., Southwestern Public Service Company, 72 FERC 61,208 at 61,996 (1995).

FN145 The Commission's practice is to define the relevant markets as those utilities directly interconnected to the applicant (first-tier markets). For each first-tier market, we consider all utilities interconnected to the first-tier utility and all utilities interconnected to the applicant as competitors in that relevant market. Thus, the competitors include the second-tier utilities directly interconnected to the relevant market and those other first-tier utilities that can reach the market by virtue of the applicant's open access transmission tariff. See, e.g., Kansas City Power & Light Company, 67 FERC 61,183 at 61,556; and Heartland Energy Services, Inc., 68 FERC 61,223 at 62,061.

146 See Wisconsin Public Service Corporation, 75 FERC 61, ___, slip op. at 6-7 (1996).

147 E.g., NRECA, TAPS, Wisconsin Coalition, APPA.

148 E.g., Wisconsin, Rosebud, NRECA, IN Com, Wisconsin Coalition, NIEP, Minnesota P&L, APPA.

FN149 See also APPA.

FN150 E.g., Wisconsin Coalition, MMWEC.

151 E.g., APPA, Wisconsin Coalition, Minnesota P&L, IN Com.

FN152 E.g., Wisconsin Coalition.

153 E.g., TAPS, Wisconsin Coalition.

154 E.g., NIEP, Wisconsin Coalition, TAPS, Environmental Action.

155 FERC Stats. & Regs. 35,531 (1996).

FN156 Our decision to review our merger policy in a separate NOI proceeding is not intended to affect a utility's business decision of whether a merger may be in the economic interest of its ratepayers and stockholders. The NOI proceeding will not prevent us from reviewing merger applications in as timely a manner as possible.

157 FERC Stats. & Regs. 32,514 at 33,093.

158 E.g., Dayton P&L, NSP, Montaup, Southwestern, Ohio Edison, Consumers Power, Allegheny, Public Generating Pool, NEPCO, Pennsylvania P&L, Southwest TDU Group, Arizona, DOD, El Paso, Florida Power Corp, AEC & SMEPA, Atlantic City, Texaco, Tampa, CSW, Central Illinois Public Service, CA Cogen, ConEd, GA Com, Consolidated Natural Gas, Ohio Valley, Pacific Northwest Coop, Salt River, Oglethorpe, Minnesota P&L, NYSEG, Brazos, Southern, Washington Water Power, CINergy, SoCal Edison, Hoosier EC.

FN159 E.g., AEC & SMEPA, Cajun, Carolina P&L, NSP, Pennsylvania P&L, UNITIL, Southwestern, CSW.

FN160 See also Dairyland, DE Muni, Arkansas Cities, Ohio Valley.

161 E.g., AEP, Associated EC, DOD, El Paso, NEPCO, Ohio Edison, PSNM, Southwest TDU Group, Utilities For Improved Transition, NYSEG, Citizens Utilities, NM Com, EGA. See also NRECA, TDU Systems, Blue Ridge, CCEM, Industrial Energy Applications, APPA, Cajun, Springfield, DE Muni, Missouri Basin MPA, TANC, Wolverine Coop Members, FL Com, Citizens Utilities, Soyland (support contract abrogation on a case-by-case basis).

FN162 E.g., Utilities For Improved Transition, NSP, Southwestern, DE Muni.

163 E.g., NRECA, CCEM, ELCON, DE Muni, Oglethorpe. Portland maintains that it would be in the public interest to abrogate existing contracts completely, but recommends that such action be taken only on a case-by-case basis.

FN164 See also VT DPS, NYMEX.

FN165 See also VT DPS, Portland.

FN166 CCEM Initial Comments at 26. See also ELCON, VT DPS, Blue Ridge, NYMEX, OK Com, Missouri Basin MPA, Texas-New Mexico, TDU Systems.

FN167 See also TDU Systems, Texas-New Mexico, TAPS, Wisconsin Municipals.

168 See also NorAm. UtiliCorp argues that existing contracts should not be allowed to extend indefinitely (as through "evergreen" clauses) without adopting comparability. See also Texaco, Wisconsin Municipals, Phelps Dodge.

169 See also Industrial Energy Applications.

170 E.g., Con Ed, Detroit Edison, IL Com.

171 Seealso Utility Workers Union, VEPCO.

172 See Pierce, Richard J., Reconstituting the Natural Gas Industry from Wellhead to Burnertip, 9 Energy L.J. 1 (1988).

173 In addition, we do not believe that unfavorable requirements contracts will derail the attainment of competitive wholesale power markets. Indeed, many of the commenters support this position and seek to retain their existing requirements contracts.

174 This is consistent with the definition of existing requirements contracts we have used for purposes of stranded cost recovery.

175 See Section IV.J.5.

176 This right of first refusal exists whether or not the customer buys power from the historical utility supplier or another power supplier. If the customer chooses a new power supplier and this substantially changes the location or direction of its power flows, the customer's right to continue taking transmission service from its existing transmission provider may be affected by transmission constraints associated with the change.

FN177 The above discussion on a right of first refusal addresses firm contract customers. However, the same logic applies to retail customers.

178 For purposes of this discussion, we define coordination agreements as all power sales agreements, except requirements service agreements. In addition, for purposes of implementing the non-discriminatory, open access requirements of the Final Rule, we are dividing bilateral coordination agreements into two general categories: (1) Economy energy coordination agreements are contracts and service schedules thereunder that provide for trading of electric energy on an "if, as, and when available" basis, but do not require either the seller or buyer to engage in a particular transaction; and (2) non-economy energy coordination agreements are any non-requirements service agreements, except economy energy coordination agreements.

FN179 The requirements for power pools and other multilateral arrangements are discussed in detail in Section IV.F.

180 Those executed prior to 60 days after publication of the Open Access Rule in the Federal Register.

FN181 The requirement to unbundle future transactions under existing economy energy coordination agreements means that if the transmission owner uses its transmission system to make economy energy coordination sales or purchases, it must take service for these transactions under its own transmission tariff after December 31, 1996.

FN182 Those executed 60 days after publication of the Open Access Rule in the Federal Register.

FN183 Accordingly, transmission service needed for sales or purchases under all new economy energy coordination agreements will be pursuant to the Final Rule pro forma tariff.

184 A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path.

FN185 Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime.

186 E.g., APPA, TAPS, NY Energy Buyers, Arcadia, Brownsville, Detroit Edison Customers, AMP-Ohio, Michigan Systems.

187 E.g., AMP-Ohio, NRECA, APPA, Detroit Edison Wholesale Customers, MMWEC, Missouri Basin MPA, Air Liquide, American Wind Energy, Associated Power, CCEM.

FN188 Some commenters propose the development of a regional rate on a postage stamp basis, without regard to distance travelled or the actual path of power flows. E.g., Air Liquide, American National Power, CA Energy Co. Several commenters do, however, propose ways to account for unscheduled flows. E.g., American Forest & Paper, DE Muni, Lower Colorado River Authority.

189 E.g., CSW, EDS Utilities, Dominion, CINergy, KS Com, CT DPUC, Com Ed, Hogan.

FN190 NYMEX favors contract path pricing because of its familiarity and believes that the issue should primarily be resolved by the transmitting utilities. AEP believes that the primary responsibility lies with industry to develop alternative pricing structures.

191 E.g., NU, NEPCO, BECO, Florida Power Corp.

192 See FERC Stats. & Regs. 31,005.

193 Associated Gas Distributors v. FERC, 824 F.2d 981, 998 (D.C. Cir. 1987), cert. denied, 485 U.S. 1006 (1988) (AGD).

FN194 We use the term "open access" to refer to a public utility's obligation to put a tariff on file offering service to eligible customers. Access is not open to all. Specifically, the tariff is not an offer to serve retail customers if state law does not permit retail wheeling.

FN195 Gulf States Utilities Company v. FPC, 411 U.S. 747, 758-59 (1973).

196 In most situations, discrimination that precludes transmission access or gives inferior access will have at least potential anticompetitive effects because it limits access to generation markets and thereby limits competition in generation. Similarly, it is probable that any transmission provision that has anticompetitive effects would also be found to be unduly discriminatory or preferential because the anticompetitive provision would most likely favor the transmission owner vis-a-vis others.

197 Order No. 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs., Regulations Preambles 30,665 (1985).

198 AGD, supra, 824 F.2d at 997.

