EXHIBIT 9

In the
United States Court of Appeals
For the Seventh Circuit

Nos. 08-1306, 08-1780, 08-2071, 08-2124, 08-2239

ILLINOIS COMMERCE COMMISSION, *et al.*,

Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION, *et al.*,

Respondents.

Petitions to Review Orders of the
Federal Energy Regulatory Commission.

ARGUED APRIL 13, 2009—DECIDED AUGUST 6, 2009

Before CUDAHY, POSNER, and TINDER, *Circuit Judges.*

POSNER, *Circuit Judge.* We have before us challenges to a decision by the Federal Energy Regulatory Commission concerning the reasonableness of rates for the transmission of electricity over facilities owned by utilities that belong to a Regional Transmission Organization (that is, a power pool) called PJM Interconnection. *PJM Interconnection, L.L.C.*, 119 F.E.R.C. ¶ 61,063 (2007), rehearing denied, 122 F.E.R.C. ¶ 61,082 (2008); see 16 U.S.C. § 824e; *Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002). ("PJM"

9

stands for "Pennsylvania-New Jersey-Maryland," but the full name is not used any more.) "RTOs are voluntary associations in which each of the owners of transmission lines that comprise an integrated regional grid cedes to the RTO complete operational control over its transmission lines." Richard J. Pierce, Jr., "Regional Transmission Organizations: Federal Limitations Needed for Tort Liability," 23 *Energy L.J.* 63, 64 (2002); see also *Regional Transmission Organizations,* 65 Fed. Reg. 810-01, 2000 WL 4557 (FERC Jan. 6, 2000); *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1,* 128 S. Ct. 2733, 2741 (2008). PJM's region stretches east and south from the Chicago area, primarily to western Michigan and eastern Indiana, Ohio, Pennsylvania, New Jersey, Delaware, Maryland, the District of Columbia, and Virginia. *PJM Interconnection, L.L.C., supra,* p. 3, see *FPL Energy Marcus Hook, L.P. v. FERC,* 430 F.3d 441, 442-43 (D.C. Cir. 2005). The region is home to more than 50 million consumers of electricity.

Two issues are presented. The first, raised by American Electric Power Service Corporation and the Public Utilities Commission of Ohio (participation by state commissions in rate proceedings before FERC is authorized by 16 U.S.C. § 825g(a); see also § 825*l*(a)), involves the pricing of electricity transmitted from the Midwest to the East through Ohio. PJM wants that transmission to be priced on the basis of the cost to American Electric of transmitting one more unit of electricity, that is, the marginal cost; and FERC agrees. Such a price excludes the cost that the company incurred when it built the transmission facilities. That cost—which American

Electric wants to be permitted to reflect in its rates—is what economists call a "sunk" cost, that is, a cost that has already been incurred. So while its financial burden can be shifted (from American Electric to the eastern utilities), the cost itself cannot be shifted, and therefore shifting the financial burden created by the cost from one set of shoulders to another will have no direct effect on service or investment.

Had FERC decided that American Electric would not be permitted to charge a price that covered the cost of building a new transmission facility or upgrading an existing one, its decision would have affected the allocation of resources and not just of money. It would have deterred the building of new facilities that benefited customers outside American Electric's service area, because building them would become an unprofitable venture. FERC emphasizes, however, that the company's existing facilities, which are all that are involved in this case, were built before 2001 when PJM became a Regional Transmission Organization, and were intended to serve American Electric's customers only. So even if the facilities had not been fully paid for, there would be no economic basis for shifting any part of their costs to other members, because American Electric did not expect when it built the facilities that any part of their cost would be defrayed by anyone besides its customers. PJM and FERC have made clear that American Electric *will* be allowed to charge a price that covers its costs for transmission to other utilities over new or upgraded facilities.

American Electric points out that some of its existing facilities are not fully depreciated. But it can continue to depreciate them over their remaining useful life in order to create an accounting reserve or obtain a tax benefit. And when it builds a new facility it will be allowed, as we said, to recover the full costs of that facility in its prices.

The company may be trying to extract a monopoly price for the use of its facilities. It stands between western sellers of electricity and their eastern customers and would like to extract a toll for giving the former passage to the latter, a toll that has no relation to its costs of rendering that service. It charged its customers for the costs of building its existing facilities and recovered those costs fully and now wants to recover them all over again from another group of consumers. And it's not as if American Electric were being required to provide transmission to the east at zero price. It is permitted to charge for the service—just not to include in the charge its sunk costs.

The second issue relates to the financing of new transmission facilities. Here the Ohio commission joins its Illinois counterpart, representing the interests of the midwestern utilities in PJM's region, in objecting to PJM's proposed method, approved by FERC, for pricing new transmission facilities that have a capacity of 500 kilovolts or more. Heretofore all new facilities in PJM's region have been financed by contributions from the region's electrical utilities calculated on the basis of the benefits that each utility receives from the facilities. This will continue to be the rule for facilities with capacities of less than 500 kV. But for the higher-voltage facilities FERC has decided that all the utilities in PJM's region should contribute pro rata; that is, their rates should be raised by a uniform amount sufficient to defray the facilities' costs.

FERC's stated reasons are that some of PJM's members entered into similar pro rata sharing agreements with each other more than forty years ago and would like to follow that precedent, that figuring out who benefits from a new transmission facility and by how much is very difficult and so generates litigation, and that everyone benefits from high-capacity transmission facilities because they increase the reliability of the entire network. Despite the stakes in the dispute—the new policy might, for example, force Commonwealth Edison to contribute hundreds of millions of dollars to an above-500 kV eastern project called "Project Mountaineer," when it would not have had to pay a dime under the benefits-based system applicable to lower-voltage transmission facilities—no data are referred to in FERC's two opinions (the original opinion and the opinion on rehearing). No lawsuits are mentioned. No specifics concerning difficulties in assessing benefits are offered. No particulars are presented concerning the contribution that very high-voltage facilities are likely to make to the reliability of PJM's network. Not even the roughest estimate of likely benefits to the objecting utilities is presented. The first sentence in this paragraph is an adequate summary of the Commission's reasoning, minus recourse to metaphor, as in the Commission's repeated references to very high-voltage facilities as the "backbone" of PJM's network. The Commission's insouciance about the basis for its ruling is mirrored by its lawyers: their brief devotes only five pages to the 500 kV pricing issue.

The objections to the Commission's ruling pivot on an asymmetry between the eastern and western portions of PJM's region. In the west the electrical generating plants usually are close to the customers—Chicago for example is ringed by power plants. As a result, relatively low-voltage transmission facilities—mainly 345 kV—are preferred. In the east, where the power plants generally are farther away from the customers, 500 kV and even higher-voltage transmission facilities are preferred, because high voltage is more efficient than low for transmitting electricity over long distances. So far as appears, few if any such facilities will be built in the objectors' service areas, that is, in the Midwest, within the foreseeable future. FERC seems not to care whether any will ever be built, because the reasons it gave for approving PJM's new pricing method are independent of where the facilities are located.

The first two reasons the Commission gave can be dispatched briefly. The fact that some of the same members of PJM who agreed to share the costs of such facilities with each other many years ago would like contributions from midwestern utilities carries no weight. The eastern utilities that created PJM refer to themselves revealingly as the "classic" PJM utilities, and the fact that these utilities thought it appropriate to share costs in 1967 says nothing about the advantages and disadvantages of such an arrangement in the larger, modern PJM network.

The Commission said that it would be inclined to defer to "regional consensus," but acknowledged there was none; the midwestern utilities are part of PJM's region but did not agree to the eastern utilities' cost-sharing proposal. As we shall see, the fact that one group of utilities desires to be subsidized by another is no reason in itself for giving them their way.

The second reason the Commission gave for approving PJM's pricing scheme—the difficulty of measuring benefits and the resulting likelihood of litigation over them—fails because of the absence of any indication that the difficulty exceeds that of measuring the benefits to particular utilities of a smaller-capacity transmission line. Like the D.C. Circuit in *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002) (citation omitted), we acknowledge "that feasibility concerns play a role in approving rates, indicating that FERC is not bound to reject any rate mechanism that tracks the cost-causation principle less than perfectly." But we also agree that "the Commission's cursory response simply will not do. At no point did the Commission explain how these considerations [that the tariffs and refund mechanism produced 'efficient price signals,' and that petitioner's requested refunds would somehow disrupt that price signaling, would be 'infeasible,' and a matter of 'unending controversy'] applied. Why, we wonder, would a different method of refunds, based more closely on cost-causation principles, jeopardize desirable price signaling or be infeasible?" *Id.*

No doubt the more a transmission facility costs, and therefore the greater the stakes in a dispute between potential contributors to that cost, the more litigation there is likely to be. But how much more (at least approximately) is the critical consideration and the Commission ignored it.

That leaves for consideration the benefits that the midwestern utilities might derive from the greater reliability that the larger-capacity transmission facilities might confer on the network as a whole. The reason for building such facilities is to satisfy the demand of eastern consumers for electricity, but the more transmission capacity there is, the less likely are blackouts or brownouts caused by surges of demand for electricity on hot summer days or by accidents that shut down a part of the electrical grid. Because the transmission lines in PJM's service region are interconnected, a failure in one part of the region can affect the supply of electricity in other parts of the network. So utilities and their customers in the western part of the region could benefit from higher-voltage transmission lines in the east, but nothing in FERC's opinions in this case enables even the roughest of ballpark estimates of those benefits.

At argument FERC's counsel reluctantly conceded that if Commonwealth Edison would derive only $1 million in expected benefits from Project Mountaineer, for which it is being asked to chip in (by its estimate) $480 million, the disparity between benefit and cost would be unreasonable. The concession was prudent. *Algonquin Gas Transportation Co. v. FERC*, 948 F.2d 1305, 1313 (D.C. Cir. 1991); *Pacific Gas & Electric Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004). As FERC itself explained in *Trans-*

continental Gas Pipe Line Corp., 112 F.E.R.C. ¶ 61,170, 61,924-61,925 (2005), "a claim of generalized system benefits is not enough to justify requiring the existing shippers to subsidize the uncontested increase in electric costs caused by the Cherokee project. . . . The rehearing applicants suggest that the use of the Cherokee shippers' transportation quantities in deriving the fuel retention percentages and their payment of such charges reduce the fuel costs borne by the existing shippers. However, they point to no evidence in the record that seeks to quantify this benefit, or even shows that such a benefit has occurred . . . . The Commission concludes that all these alleged benefits are simply too speculative and unsupported to be taken into account."

FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. "'[A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.' *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000); *Pacific Gas & Elec. Co. v. FERC*, No. 03-1025, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004). Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004); see also *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346-47 (D.C. Cir. 2009); *Sithe/Independence Power Partners, L.P. v. FERC, supra*, 285 F.3d at 4-5; Federal Power Act, 16 U.S.C. § 824d. To the extent that a utility benefits from the costs of new facilities, it may be said to have "caused" a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed. But as far as one can tell from the Commission's opinions in this case, the likely benefit to Commonwealth Edison from new 500 kV projects is zero. The opinion on rehearing attributes the need for new transmission capacity in PJM to the threat of "degraded reliability in *Eastern* PJM," 122 F.E.R.C. ¶ 61,082, p. 13 (emphasis added), and nowhere do the Commission's opinions suggest that degraded reliability is a danger in Midwestern PJM.

No doubt there will be *some* benefit to the midwestern utilities just because the network *is* a network, and there have been outages in the Midwest. But enough of a benefit to justify the costs that FERC wants shifted to those utilities? Nothing in the Commission's opinions enables an answer to that question. Although the Commission did say that a 500 kV transmission line has twice the capacity of a 345 kV line, it added that "the *reliability* of 500 kV and above circuits in terms of momentary and sustained interruptions is 70 percent more reliable than 138 kV circuits and 60 percent more than 230 kV circuits on a per mile basis," *PJM Interconnection, L.L.C., supra,* 119 F.E.R.C. ¶ 61,063, p. 23; 122 F.E.R.C. ¶ 61,082, p. 16 (emphasis added)—but did not compare the reliability of a 500 kV line to that of a 345 kV line, even though network reliability is the benefit that the Commission thinks the midwestern utilities will obtain from new 500 kV lines in the East.

Rather desperately FERC's lawyer, and the lawyer for the eastern utilities that intervened in support of its ruling, reminded us at argument that Commission has a great deal of experience with issues of reliability and network needs, and they asked us therefore (in effect) to take the soundness of its decision on faith. But we cannot do that because we are not authorized to uphold a regulatory decision that is not supported by substantial evidence on the record as a whole, or to supply reasons for the decision that did not occur to the regulators. E.g., 5 U.S.C. § 706; *Bethany v. FERC*, 276 F.3d 934, 940 (7th Cir. 2002); *Central Illinois Public Service Co. v. FERC*, 941 F.2d 622, 627 (7th Cir. 1991); *Pacific Gas & Electric Co. v. FERC, supra*, 373 F.3d at 1319. The reasons that did occur to FERC are inadequate.

We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. *Midwest ISO Transmission Owners v. FERC, supra*, 373 F.3d at 1369 ("we have never required a ratemaking agency to allocate costs with exacting precision"); *Sithe/Independence Power Partners, L.P. v. FERC, supra*, 285 F.3d at 5. If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine;

the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. E.g., *Western Massachusetts Elec. Co. v. FERC*, 165 F.3d 922, 927 (D.C. Cir. 1999). But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." *Midwest ISO Transmission Owners v. FERC*, *supra*, 373 F.3d at 1368. Nor did it in the *Western Massachusetts* case.

In *Midwest ISO*, where the objecting utilities contended that they were being asked to pay far more than their share of the benefits—which they said was a measly 5 percent—the court found that they were misrepresenting the record. 373 F.3d at 1370. There is no comparable basis on which to affirm the Commission's decision in this case. Our review of decisions by FERC is deferential, e.g., *Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C. Cir. 1992); "we require only that the agency have made a reasoned decision based upon substantial evidence in the record." *Id.* But the Commission failed to do that, and so the case must be remanded for further proceedings; we intimate no view on their outcome.

To summarize, the petitions for review that concern the pricing of existing transmission facilities are denied, but the petitions concerning the pricing of new facilities that have a capacity of 500 kilovolts or more are granted.

CUDAHY, *Circuit Judge*, concurring in part and dissenting in part. I concur fully in the majority's approval of FERC's rate design for existing facilities' transmission costs. I write separately to express my concerns over the majority's disapproval of the proposed rate design for new transmission lines operating at voltages at or in excess of 500,000 volts.

The United States is now engaged in an urgent project to upgrade its electric transmission grid, which for years has been generally regarded as inadequate,[1] and may become more deficient with the addition of major new anticipated loads.[2] The existing transmission system originally served vertically integrated utilities that built their own generation relatively close to their customers. The system was not designed for long-distance power

---

[1] *E.g.*, *House Report on the Energy Policy Act of 2005*, H.R. Rep. No. 109-215(I), at 171 ("Investment in electric transmission expansion has not kept pace with electricity demand. Moreover, transmission system reliability is suspect as demonstrated by the blackout that hit the Northeast and Midwest in August of 2003. Legislation is needed to address the issues of transmission capacity, operation, and reliability. In addition, state regulatory approval delays siting of new transmission lines by many years. Even if a project is completed, there is uncertainty as to whether utilities will be able to recover all of their investment, which hinders new transmission construction.").

[2] *See, e.g.*, Argonne, *Impact of Plug-in Hybrid Electric Vehicles on the Electricity Market in Illinois*, available at http://www.dis.anl.gov/news/Illinois_PluginHybrids.html (visited 7/27/09).

transfers between different parts of the country. The inadequacy of the present network and the urgency of the need for its improvement has only been exacerbated by the additional burdens imposed by deregulation (or restructuring), which "unbundled" generation and transmission and created a need to bring power from distant generators.[3] Additional challenges have been posed by the demand for power from renewable generation sources (such as wind farms) that are often located in places remote from centers of electric consumption.[4]

Long-distance transmission, which inherently presents challenges to reliability, is accomplished most efficiently by the highest levels of voltage—500 kV and above. According to FERC, "500 kV and above circuits . . . [are] 70 percent more reliable than 138 kV circuits and 60 percent more than 230 kV circuits on a per mile basis." *PJM Interconnection LLC*, 122 FERC ¶ 61,082, 2008 WL 276596, at *16 (Jan. 31, 2008) (order on rehearing). Further, because power transfer capability increases with the square of voltage,[5] extra-high voltage transmission also

---

[3] *See* Mark Cooper, *Electricity Deregulation Puts Pressure on the Transmission Network and Increases its Cost*, available at http://www.consumersunion.org/Transmission%20brief%208.27.pdf (visited 7/27/09).

[4] *See* Matthew L. Wald, *Debate on Clean Energy Leads to Regional Divide*, N.Y. Times, July 14, 2009, at A13.

[5] *See generally* Peter W. Sauer, *Reactive Power and Voltage Control Issues in Electric Power Systems*, Applied Mathematics for (continued...)

facilitates enormous transfers of power: "the maximum transfer capability at 500 kV and above is approximately 6 times greater than a similar transmission line operated at 230 kV and more than twice that at 345 kV . . . ." *Id.* In light of its unique contributions to reliability and transfer capability, extra-high voltage transmission is especially fitted to be financed equally by all utilities that benefit from its role as the "backbone" of the system.[6] Pro rata rates for extra-high voltage transmission, through their simplicity of application, also provide a strong incentive to build transmission undeterred by fruitless controversy over the allocation of costs.

It is significant that FERC's conclusion that the costs of extra-high voltage transmission facilities should be shared is consistent with the proposals of fifteen of PJM's seventeen members. In the course of this proceeding,

---

[5] (...continued)
Restructured Electric Power Systems: Optimization, Control, and Computational Intelligence (Joe H. Chow, Felix F. Wu & James A. Momoh, eds.) (2005).

[6] These are "backbone" facilities because they "integrate major system resources," *Pacific Gas & Elec. Co.*, 53 FERC ¶ 61146, 61520-21 & n.65, 1990 WL 319356, at *10 (Oct. 31, 1990), by facilitating major transfers of power between and among regions. To my knowledge, no court prior to ours has objected to the metaphor. *See Public Serv. Co. of Ind., Inc. v. FERC*, 575 F.2d 1204, 1217 (7th Cir. 1978); *see also Cal. Dep't of Water Res. v. FERC*, 489 F.3d 1029, 1035 (9th Cir. 2007); *Boston Edison Co. v. FERC*, 441 F.3d 10, 11 (1st Cir. 2006); *Cajun Elec. Power Coop., Inc. v. FERC*, 924 F.2d 1132, 1134 (D.C. Cir. 1991).

various parties proposed voltages lower than 500 kV as the threshold above which proportional cost-sharing should apply. Although PJM's members were unable to agree on a specific voltage cutoff, they were broadly in agreement that the rate structure should be designed to share the costs of facilities providing general systemic benefits. There was thus an effort by many parties to broaden the area of rate-simplification by enlarging the set of new transmission facilities to be governed by cost-sharing, not to narrow or eliminate it. I think these efforts illustrate the value of simplification and the difficulties in the design of a transmission rate structure that attempts rigidly and in all circumstances to trace benefits to specific utilities.

However theoretically attractive may be the principle of "beneficiary pays," an unbending devotion to this rule in every instance can only ignite controversy, sustain arguments and discourage construction while the nation suffers from inadequate and unreliable transmission. Unsurprisingly, it is not possible to realistically determine for each utility and with reference to each major project the likelihood that rate-simplification will reduce litigation, or to calculate the precise value of not having to cover the costs of power failures and of not paying costs associated with congestion, and all this over the next forty to fifty years. Concerns about the real value to individual utilities of the stability and efficiency provided by improvements to the backbone grid are answered by their voluntary participation in the power pool and its collaborative "RTEP" (or regional transmission expansion planning) process. Rate-making based on cost causation is assured by this process, since universal cost-sharing is recommended only when developments are found to benefit the integrated system as a whole.[7]

Contrary to the majority's suggestion, FERC did not violate principles of "cost causation" by failing to propose a number that would represent the specific monetary benefits to each utility of a more reliable network. Cost causation requires that "approved rates reflect to some degree the costs actually caused by the customer who must pay them." *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (Roberts, J.) (quoting *KN Energy, Inc. v. FERC*, 968 F.2d 1294, 1300 (D.C. Cir. 1992)) (internal quotation marks omitted). However, until today, no court has found that cost causation requires FERC to monetize the benefits of reliability improvements in

---

[7] "Project Mountaineer," with which the majority seems particularly concerned, is no exception. Project Mountaineer is a plan to construct hundreds of miles of 500 and 765 kV linkages between eastern and western PJM. The PJM literature, to which Commonwealth Edison could have objected but did not, indicates that Project Mountaineer was a response to the nearly 200% increase in congestion costs from 2004 to 2005. Ventyx, *Major Transmission Constraints in PJM*, at *3 n.4 (2007), available at http://www.ventyx.com/pdf/wp07-transmission-constraints.pdf (visited 7/14/09). These increased congestion costs were partly due to the expansion of PJM's footprint. *Id.* As part of its cost allocation process, PJM determined that Project Mountaineer "would bring about substantial congestion relief and reliability improvements increasing Midwest-to-east transfers by 5,000 MW." *Id.* at *3.

order to share the costs. Indeed, the cases the majority cites support the opposite conclusion. Most notably, in *Midwest ISO*, the panel was quite clear that utilities that draw benefits from being a part of a power pool should share the cost of *having* a power pool. *Id.* at 1371. As then-Judge Roberts explained, "upgrades designed to preserve the grid's reliability constitute system enhancements that *are presumed to benefit the entire system.*" *Id.* at 1369 (internal quotation marks, citations and alterations omitted, and emphasis added); *see also Entergy Servs., Inc. v. FERC*, 319 F.3d 536, 543 (D.C. Cir. 2003); *Western Massachusetts Elec. Co. v. FERC*, 165 F.3d 922, 927 (D.C. Cir. 1999). Since there is a *presumption* that enhanced reliability benefits all of the systems members, Commonwealth Edison (ComEd) can be required to bear a proportional share of an improvement's costs even where it is not possible to determine precisely how much it benefits. Put otherwise, the burden is on ComEd to show that it would *not* benefit from the newly planned transmission facilities; the burden is not on FERC to estimate how much ComEd would benefit from a more reliable grid.

Indeed, in *Midwest ISO*, the panel *rejected* the objecting utility's argument that it could not be made to pay sixty to seventy percent of an investment's costs because it would obtain only five percent of the benefits. 373 F.3d at 1370. As the majority notes, the panel found no record support for the utility's claim that its benefits would be so low. (Maj. Op. at 12.) However, the panel also held that cost causation principles do not require the costs of a new facility to be apportioned based on the objecting utility's actual *use* of that facility. To the contrary, the "benefits" of system enhancements must be understood more broadly than this. Again, then-Judge Roberts:

> even if they are not in some sense *using* the ISO [roughly a term for a power pool], the MISO Owners still benefit from *having* an ISO. In this sense, MISO is somewhat like the federal court system. It costs a considerable amount to set up and maintain a court system, and these costs—the costs of *having* a court system—are borne by the taxpayers, even though the vast majority of them will have no contact with that system (will not *use* that system) in any given year . . . The MISO Owners' position is tantamount to saying that if they are not a litigant, they should not be made to pay for any of the costs of *having* a court system. Since the MISO Owners do, in fact, draw benefits from being a part of the MISO regional transmission system, FERC correctly determined that they should share the cost of *having* an ISO.

Id. at 1371. I fear that the majority has lost sight of this basic principle.[8]

---

[8] The other cases on which the majority relies also do not hold that FERC is required to explain the benefits of reliability. For instance, in *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305 (D.C. Cir. 1991), the court rejected FERC's proposal to share the costs of a new gas pipeline because FERC had not provided *any* evidence that the pipeline would provide system-wide benefits. *Id.* at 1313. In the present case, by contrast, there

(continued...)

Because the majority's decision is based on an unusually narrow conception of cost-causation, its characterizations of FERC's and the intervenor's arguments as "insouciant" (Maj. Op. at 5) and "desperate" (Maj. Op. at 11) strike me as conspicuously misplaced. FERC responded to ComEd's objections by indicating that the proposed projects would improve reliability and reduce congestion. *See PJM Interconnection*, 2008 WL 276596, at *16. It did not explain how PJM's members benefit from a reliable network because no court had hitherto required it to do so. Until now, it went without saying that network reliability benefits the network's members. This is not insouciance; "[e]xplanations come to an end somewhere." Ludwig Wittgenstein, *Philosophical Investigations* §1 (G.E.M. Anscombe trans., 1968).

The big picture here is that FERC's proposal to spread the cost of very high voltage transmission on a uniform

---

[8] (...continued)
is no dispute that the transmission facilities at issue would increase network transfer capacity and improve network reliability.

Along the same lines, *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009), provides no support at all for the majority's robust understanding of the requirements of cost causation. In that case, the D.C. Circuit *rejected* Alcoa's claim that it was being asked to pay more than its fair share of the costs of maintaining network reliability, holding instead that because rate design rests on technical issues and policy judgments that lie at the core of the regulatory mission, FERC's explanation for its rate scheme "although admittedly spare, is nonetheless adequate." *Id.* at 1347-48.

basis seems to me in the interest of efficient, high-capacity transfer capability and of the closely linked improvement of reliability, which affects the system generally.[9] Deregulation created a demand for competitive sources of power, often at a distance. Because 500 kV and above lines satisfy these new systemic needs, their separate treatment for rate-making purposes is both sensible and innovative. While an effort to identify specific benefits to

---

[9] Indeed, the majority concedes that reliability problems affect all of the system's users when it acknowledges that failures in one part of an integrated network can affect the supply of electricity in other parts of the network. (Maj. Op. at 8). So-called "cascading outages" have occurred on a number of occasions in the recent past. Most notably, in 2003 a power failure that started in Ohio spread through eight states, including parts of PJM's footprint, leaving 50 million people without power and causing an estimated $12 billion in economic losses. *E.g.*, Peter Fox-Penner, *A Year Later, Lessons From the Blackout*, N.Y. Times, Aug. 15, 2004, at 14WC. As the majority notes, FERC has not estimated the probability that degraded reliability in Eastern PJM could affect Midwestern PJM. However, even if this probability is vanishingly small, a very low number multiplied by billions of dollars may still yield a very high number. Further, there is no reason to suppose that ComEd's customers are unaffected by problems with the reliability of the PJM grid. By one estimate, power outages and disturbances cause $4 to $7 billion in damages per year in Illinois alone. *See* Primen, *The Cost of Power Disturbances to Industrial & Digital Economy Companies* (June 29, 2001), at D-1, available at http://www.onpower.com/pdf/EPRICostOfPowerProblems.pdf (visited 7/8/09).

specific utilities is a traditional rate design approach and may be appropriate for most electric plant facilities, it may miss the forest and focus on the trees when applied to very high voltage "backbone" facilities having a generalized role in supporting reliability and high capacity power transfer. Perhaps as important in this picture is the urgency of the need to build transmission and the need for incentives to that end. Pro rata assignment of costs eliminates not only lawsuits but nitpicking controversies of every sort and delays standing in the path of action. From that point of view, I think FERC may be in a better position to implement a policy leading to prompt improvement in a deficient transmission grid than this court, focused as it is on the inevitable complaints of utilities demanding more for their money. I therefore respectfully dissent from the majority's unfortunate rejection of FERC's rate scheme for new transmission lines carrying 500 kV or higher.

EXHIBIT 10

State of New Jersey
Highlands Water Protection and Planning Council
100 North Road (Route 513)
Chester, New Jersey 07930-2322
(908) 879-6737
(908) 879-4205 (fax)
www.highlands.state.nj.us

Highlands Council
New Jersey

JON S. CORZINE
Governor

JOHN R. WEINGART
Chairman

EILEEN SWAN
Executive Director

Contact: Craig Garretson, Manager of Communications
(908) 879-6737 ext. 108 or craig.garretson@highlands.state.nj.us

FOR IMMEDIATE RELEASE
May 19, 2009

New Proposal for Power Line Project

Utility agrees to amend proposed Susquehanna-Roseland project to be consistent with Highlands Regional Master Plan; will pay for land preservation in Highlands

CHESTER, N.J. – If the proposed Susquehanna-Roseland 500-kv Transmission Line project is approved by the Board of Public Utilities, PSE&G will work with the Highlands Water Protection and Planning Council and the New Jersey Department of Environmental Protection on a new comprehensive management plan that will protect the resources of the environmentally sensitive Highlands Region and address many of the concerns brought up by the Highlands Council staff, municipalities, environmental groups, and property owners when the project was initially proposed.

PSE&G will work with the Highlands Council staff on a protective plan to address proposed construction along its existing 26-mile right-of-way. The plan is designed to avoid, minimize or mitigate the impact of the project in the Highlands Region, in order to be consistent with the Highlands Regional Master Plan. The comprehensive management plan includes a contribution of $18.6 million toward the acquisition or stewardship of priority lands in the Highlands Region. The application from PSE&G makes it clear that it is contingent upon approval by the Board of Public Utilities.

A major change to the proposal is a relocation of a switching station that was intended for ecologically sensitive land in Jefferson Township, a location that was of primary concern to the Highlands Council. The switching station will be moved to a site in Hopatcong Borough, and the utility has agreed to construct a smaller station utilizing Gas Insulated Switching gear technology. This relocation also means 13 fewer towers will have to be constructed. Other changes to the proposed project include new management plans, consistent with NJDEP permit requirements, for work in forested, wetlands and critical habitat areas; a restoration plan for streams and riparian habitats; and a historic and archaeological resources protection plan.

PSE&G's first proposal for the project was considered by Council staff to be inconsistent with the Highlands Regional Master Plan in December. In response, PSE&G requested additional time to work on the issues identified in the Highlands Consistency Determination.

"The Highlands Council will examine the amended application for consistency with the Highlands Regional Master Plan, which provides the highest standard of protection for the region," said Highlands Council Executive Director Eileen Swan. "The Council will once again solicit public comments before making any final determination on the project."

PSE&G's amended application has been posted to the Highlands Council website's Project Review page: http://www.highlands.state.nj.us/njhighlands/projectreview/pseg_amended_0519.pdf.

EXHIBIT 11

Alexander C. Stern
Assistant General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102-4194
tel: 973.430.5754 fax: 973.430.5983
email: alexander.stern@pseg.com

PSEG
Services Corporation

August 21, 2009

VIA HAND DELIVERY

Joseph L. Fiordaliso, Commissioner
New Jersey Board of Public Utilities
Two Gateway Center, 8th Floor
Newark, New Jersey 07102

Re: **IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR A DETERMINATION PURSUANT TO THE PROVISIONS OF N.J.S.A. 40:55D-19**

(SUSQUEHANNA-ROSELAND)

BPU DOCKET NO. EM09010035

Dear Commissioner Fiordaliso:

Please be advised that, in accordance with a mitigation plan accepted and approved by the New Jersey Highlands Council, Public Service Electric and Gas Company ("PSE&G") has expressed a willingness to move construction of a Switching Station included as part of the Susquehanna-Roseland Project ("the Project") from Jefferson Township to the Borough of Hopatcong. Although PSE&G's filing in this matter remains unchanged by the Highlands Council's determination, in furtherance of the relocation of the switching station, PSE&G wishes to provide you and the parties in this proceeding with the following additional information.

By way of background, on June 26, 2009, the New Jersey Highlands Council voted in favor of a Comprehensive Mitigation Plan ("Mitigation Plan") submitted by PSE&G as an amendment to its Highlands Applicability Determination ("HAD"). Based upon input from the New Jersey Department of Environmental Protection, the Highlands Council and the public, PSE&G submitted the Mitigation Plan, which expressed a willingness to take certain actions to reduce environmental impacts in the Highlands – a statutorily protected region of the state. PSE&G offered to take these actions because doing so would recognize the sensitive resources within the Highlands region that would be traversed by the upgraded utility line while also enabling PSE&G to be able to continue to ensure safe, adequate and proper electric service in accordance with N.J.S.A. 48:2-1 et seq.

Specifically, the Mitigation Plan involves:

1) Relocating a required switching station from Jefferson Township to the Borough of Hopatcong -- significantly reducing the permanent impacts from this required upgrade;
2) Providing for use of existing roads for access to the maximum extent possible; and
3) Incorporating a framework for a Comprehensive Management Plan in response to projected impacts to the Highlands and other resources as part of the proposed Project.

It is primarily with respect to measure (1) above that PSE&G is submitting this letter to the Board. Should the Board conclude in accordance with N.J.S.A. 40:55D-19 that the Project is "reasonably necessary for the service, convenience, or welfare of the public," the Highlands Council has determined that the Mitigation Plan would minimize the impacts of the Project on the environment in the statutorily protected Highlands region while enabling PSE&G to ensure safe, reliable electric service for years to come. PSE&G agrees with and is prepared to honor this conclusion and to take the necessary actions associated with the approved Mitigation Plan.

Within the Highlands Preservation Area, PSE&G has identified a new location in the Borough of Hopatcong for the proposed switching station that would have been located in Jefferson Township. PSE&G agrees with and is willing to accept the determination of the Highlands Council that this change substantially reduces the amount of forest clearing in the Preservation Area that otherwise would have been needed for the Project. A secondary benefit identified in the Mitigation Plan was the reduced need for specific transmission structures including approximately eleven (11) structures, many of which would have been required around Lake Winona. Finally, advanced switching station design techniques would allow PSE&G to reduce the footprint of the switching station from that which was originally proposed.

a. Engineering and Design

In the Mitigation Plan PSE&G expressed a willingness to design the Hopatcong Switching Station as a Gas Insulated Switchgear station ("GIS") as opposed to the open air switching station proposed in Jefferson. The GIS design would reduce the station's footprint and thereby provide further environmental mitigation. PSE&G is willing to build the Hopatcong Switching Station in accordance with this design, as identified in the Mitigation Plan. A discussion of GIS technology is included in the pre-filed testimony of Richard I. Jacober. Additionally, since it is now possible we will proceed with this approach, Hopatcong Switching Station Site Plans and Elevation Drawings are attached hereto as Exhibit RIJ-3.

c. **Routing**

There would be no significant change to the route of the proposed line caused by acceptance of the Mitigation Plan approved by the Highlands Council. The proposed line with the Hopatcong Switching Station included is attached hereto as Sheets 17, 17A and 18 to Exhibit RFC-3. These sheets would replace Sheet 17 of RFC-3 that was submitted to the Board with PSE&G's petition. Briefly, the route would continue to utilize the existing right-of-way through Andover, Stillwater and Fredon Townships. Continuing east into Byram, then Sparta, the route would enter the Highlands Planning and Preservation Area before interconnecting with a proposed new switching station in the Borough of Hopatcong. Leaving the Hopatcong switching station, the route would head east through Sparta again and into Jefferson Township and continues as described in the pre-filed testimony of Jack Halpern. Although it would be necessary for PSE&G to acquire property in Hopatcong, these acquisitions have or are in the process of occurring and, as previously indicated, PSE&G is prepared to take all necessary actions to effectuate construction of the Hopatcong Switching Station in compliance with the approved Mitigation Plan.

d. **Need**

The proposed Hopatcong switching station would be very important to the overall Project since it would facilitate the interconnection of the Susquehanna-Roseland 500 kV line with the Branchburg to Ramapo transmission line as discussed in the pre-filed testimony of Esam A.F. Khadr. In fact, the Hopatcong Switching Station would actually be closer to the Branchburg to Ramapo line than the proposed Jefferson Switching Station would have been.

Again, PSE&G is prepared to honor its commitments under the Mitigation Plan should the Board conclude the Project is "reasonably necessary" in accordance with N.J.S.A. 40:55D-19.

Thank you for your consideration of this matter.

Respectfully submitted,

Alexander C. Stern

Alexander C. Stern, Esq.

ACS/jb

cc: Service List
(via overnight mail w/enclosures to Counsel of Record)

EXHIBIT 12

http://74.125.47.132/search?q=cache:7Bi9ZpA-Sq8J:online.wsj.com/article/SB125003563550224269.html+%22Wall+Street+Journal%22+%22Electricity+Prices+Plummet%22&cd=1&hl=en&ct=clnk&gl=us&client=firefox-a

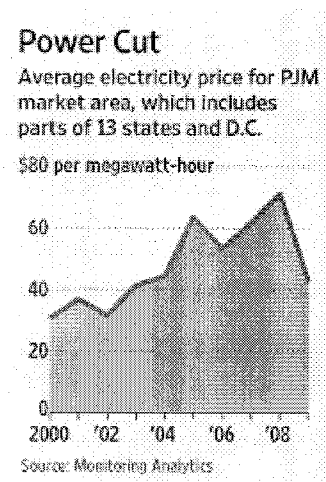
- THE WALL STREET JOURNAL. WSJ.com
- AUGUST 12, 2009

Electricity Prices Plummet

By REBECCA SMITH

Slack demand for electricity across the U.S. is leading to some of the sharpest reductions in power prices in recent years, offering a break for consumers and businesses who just a year ago were getting crunched by massive electricity bills.

On Friday, the nation's largest wholesale power market serving parts of 13 states east of the Rockies is expected to report that electricity demand fell 4.4% in the first half of the year. That helped to push down spot market prices by 40% during the first half of this year.



Wholesale electricity -- power furnished to utilities and other big energy users -- cost an average of $40 a megawatt hour in the region, down from $66.40 a year earlier. The price declines in this market, which extends from Delaware to Michigan, come on top of a 2.7% drop in energy use in 2008 over 2007.

The falloff in demand represents a reversal of what has been one of the steadiest trends in business. For decades, the utility sector could rely on a gradual increase in electricity demand. In 45 of the past 58 years, year-over-year growth exceeded 2%. In fact, there only have been five years since 1950 in which electricity demand has dropped in absolute terms.

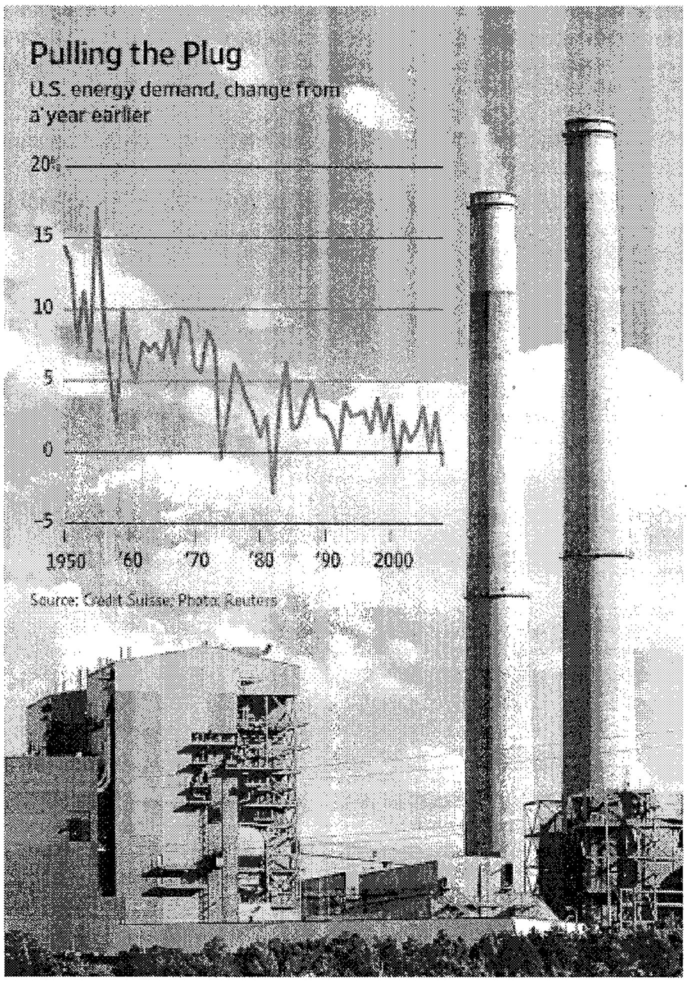
But this year is shaping up to have the sharpest falloff in more than half a century, and coming on top of declines in 2008, could be the first period of consecutive annual declines since at least 1950.

Dramatic price reductions don't immediately mean lower power bills for all consumers. That's because many customers pay prices based on long-term contracts. But lower prices will have a softening effect over time.

In California and Texas, a combination of cheap natural gas and lower industrial demand is putting pressure on prices.

In the Houston pricing zone, which has many power-gobbling refineries and chemical plants, the spot market price was $61.82 in June, versus $129.48 a megawatt hour a year earlier. Power demand in Texas is down 3.2% so far this year due to business contraction and reductions in employment which are causing many households to economize.

Just a year ago, many businesses and residential customers were reeling from electricity prices on the spot market that had spiked to historic highs, driven by high fuel prices and hot summer weather. Some businesses curtailed their operations because electricity and natural gas were too pricey.



But the flagging economy has resulted in a slump in demand that has jolted some energy markets. American Electric Power Co. and Southern Co., for example, both reported double-digit drops in industrial electricity use for the past quarter.

Meanwhile, natural gas, which strongly influences electricity prices, has fallen below $4 per million BTUs, or British thermal units. That's down from $12 at last year's peak.

For many businesses, the cost of electricity represents one of the few bright spots in a dismal economy. Andy Morgan, president of Pickard China Inc. in Antioch, Ill., which makes fine china, figures his electricity cost is down 30% to 40%.

Last year, when everything was spiking, he looked at different options -- including negotiating a fixed-price contract for energy with a supplier. He says he held off and now he's happy he did.

"We've definitely reaped savings," says Mr. Morgan, adding that "especially in a down economy, you'll take whatever you can get. That's one of the few blessings during this storm."

Slowdowns at major industrial companies such as Alcoa Inc. help account for the decline in electricity usage this year. The recession and drop in consumer demand for products that contain aluminum has caused the company to idle 20% of its smelting capacity world-wide this year.

In the U.S. the company has cut production at smelters, which are traditionally big energy users, in New York, Tennessee and Texas. Kevin Lowery, a company spokesman, said he did not believe that Alcoa has saved much money thus far because the company primarily purchases electricity through 25- to 35-year contracts.

Steel Dynamics Inc. is benefiting from lower pricing. The company operates five steel mills, with four purchasing electricity at spot market prices in Indiana, Virginia and West Virginia. The benefit, though, is smaller than it might be because the steelmaker is producing less steel this year.

"We're producing fewer tons, but every ton we produce we seek to minimize the costs and electricity is one of those," said Fred Warner, a company spokesman. Its mills are running at 50% capacity this year, down from 85% capacity last year.

Some wonder whether the deregulated markets of the Eastern U.S., Midwest, Texas and California will be especially hard hit if demand comes roaring back. That's because utilities in these markets no longer are required to build new resources. It's left up to the power generators to determine when the market conditions are ripe.

"There's more supply than demand and prices are really low so it doesn't make sense to build anything," says John Shelk, president of the Electric Power Supply Association in Washington, D.C., a group that represents power generators.

Many electricity markets throughout the country have implemented demand reduction programs that give consumers a further incentive to reduce power use. The 13-state PJM Interconnection market has been one of the most aggressive -- and has seen one of the steepest price drops.

A new report from the region's official market monitor found a strong correlation between falling prices and an increase in demand-reduction programs. In the PJM market, energy users can collect money through an auction process for pledging to cut energy use in future periods.

In May, PJM conducted an auction to ensure it will have the resources it believes it will need in 2012-13. About 6% of the winning bids came from those who pledged to cut energy use by a total of 8,000 megawatts in that future period.

EXHIBIT 13

http://www.pseg.com/media_center/pressreleases/articles/2009/2009-10-28.jsp

October 28, 2009

PSEG Announces 2009 Third Quarter Results

$0.96 Per Share from Continuing Operations
$0.92 Per Share of Operating Earnings

Results reflect impact on demand from weather and economic conditions

(October 28, 2009 – Newark, NJ) - Public Service Enterprise Group (PSEG) reported today third quarter 2009 Income from Continuing Operations of $488 million or $0.96 per share as compared to Income from Continuing Operations for the third quarter of 2008 of $476 million or $0.94 per share. Net Income for the third quarter 2009 was the same as Income from Continuing Operations. Including the effect of gains on the sale of discontinued operations of $180 million or $0.35 per share, PSEG reported Net Income for the third quarter of 2008 of $656 million, or $1.29 per share. Operating Earnings for the third quarter of 2009 were $464 million or $0.92 per share compared to the third quarter of 2008 Operating Earnings of $477 million or $0.94 per share.

PSEG believes that the non-GAAP financial measure of "Operating Earnings" provides a consistent and comparable measure of performance of its businesses to help shareholders understand performance trends. Operating Earnings exclude the impact of the sale and/or impairment of certain non-core assets and the impact of returns/(losses) associated with Nuclear Decommissioning Trust (NDT) investments and Mark-To-Market (MTM) accounting. The table below provides a reconciliation of PSEG's Net Income to Operating Earnings (a non-GAAP measure) for the third quarter. See Attachment 12 for a complete list of items excluded from Income from Continuing Operations in the determination of Operating Earnings.

PSEG CONSOLIDATED EARNINGS (unaudited)
Third Quarter Comparative Results
2009 and 2008

	Income ($millions)		Diluted Earnings Per Share	
	2009	**2008**	**2009**	**2008**
Net Income	$488	$656	$0.96	$1.29
Less: Income from Discontinued Ops	--	180	--	0.35
Income From Continuing Ops	$488	$476	$0.96	$0.94
Less: Excluded Items	24	(1)	0.04	--
Operating Earnings (Non-GAAP)	$464	$477	$0.92	$0.94
		Avg. Shares	**507M**	**508M**

"We faced challenging market conditions in the third quarter. Cooler than normal weather and continued weak economic conditions combined to reduce demand and lower pricing," said Ralph Izzo, chairman, president and chief executive

13

officer. He went on to say "We were able to offset most of the decline in demand through our hedging strategy resulting in recontracting at higher prices, our asset mix, our employees' focus on cost reduction and sales in our lease portfolio, which were undertaken at favorable terms to reduce our tax risk. These factors, however, as we noted last quarter, continue to make it difficult to meet the upper end of our 2009 earnings guidance range of $3.00-$3.25 per share. Although impacted by weather and a weaker economy, we are also positioning ourselves to meet our long-term objectives with a focus on profitable investment, an increase in operating efficiency and a strong balance sheet."

PSEG's operating company guidance reflects the transfer of the Texas gas-fired generating assets from Holdings to Power which was effective on October 1, 2009. In addition, guidance reflects the impact of the Holdings debt exchange with Power which resulted in a premium payment of $20 million after-tax ($0.04 per share). The premium was charged against Holdings results, but deferred at the Parent level, as this transaction was treated as a debt refinancing.

Updated Operating Earnings guidance by subsidiary for 2009 is shown below:

2009 Operating Earnings Guidance ($ millions)	
PSEG Power	$1170-$1245
PSE&G	315-335
PSEG Energy Holdings	25-45
PSEG Parent	10-15
Operating Earnings	$1520-1640
Earnings Per Share	$3.00-3.25

Operating Earnings Review and Outlook by Subsidiary

See Attachment 6 for detail regarding the quarter-over-quarter reconciliations for each of PSEG's businesses.

PSEG Power

PSEG Power reported operating earnings of $339 million ($0.67 per share) for the third quarter of 2009 compared with operating earnings of $360 million ($0.71 per share) for the third quarter of 2008. PSEG Power's results in the third quarter of 2009 were hurt by a decline in demand ($0.08 per share) and a migration of customers away from full requirements contracts in a period of low commodity pricing ($0.04 per share). Earnings were also affected by trading ($0.01 per share), which will reverse in the fourth quarter. Generation in the third quarter declined by 10% as a result of a contraction in economic activity and cooler than normal weather. This decline in demand and period of lower commodity pricing was partially offset by lower cost to serve ($0.05 per share) as well as a reduction in operating and maintenance expense ($0.03 per share) and lower financing costs ($0.01 per share).

Power met its load obligations with higher output from its nuclear fleet including strong summer generation from the nuclear units. Salem 2 completed a record

515-day run before entering a refueling outage. Nuclear generation increased 1.4% during the quarter and supplied 56% of Power's obligations compared with 49% in the year-ago quarter. During the quarter, our nuclear fleet operated at an average capacity factor of 94.6%, bringing the capacity factor for the nine months ended September 30, 2009 to 93.8% (versus 93.1% for the first nine months of 2008). A reduction in the cost of gas allowed the combined cycle fleet to hold its volume at the displacement of the coal-fired stations. The operation of our diverse generating fleet supported Power's gross margins during the quarter.

Power's gross margins for the full year are benefiting from higher contracted prices, a decline in fuel costs and stronger performance from the nuclear fleet than originally forecast. Based on performance of the nuclear fleet during the first nine months of the year, the nuclear fleet's full year capacity factor could advance to 92%-93% versus a forecasted capacity factor of 91-92% and 2008's capacity factor of 92.6%. The improvement in gross margin is expected to offset a forecasted decline in fossil generation for the full year. We are, as a result, maintaining our forecast of Power's full year operating earnings of $1,170-$1,245 million. At year-end, Power's operating results will reflect the full-year earnings impact of the October 1, 2009 transfer of the 2,000 MW of gas-fired assets in Texas from Holdings to Power as well as interest expense associated with newly issued debt resulting from the exchange of Holdings' debt in September.

PSE&G

PSE&G reported operating earnings of $87 million ($0.17 per share) for the third quarter of 2009 compared with operating earnings of $97 million ($0.19 per share) for the third quarter of 2008.

Electric revenues declined during the third quarter by $0.02 per share. The results were equally affected by a decline in economic activity and cooler than normal weather. The reduction in electric revenue was offset by an increase in transmission rates effective on October 1, 2008 ($0.02 per share). Operating and maintenance expense associated with higher pension costs increased $0.02 per share.

Electric and gas demand in 2009 have been heavily influenced by the weather and continued impact of economic conditions. Winter weather was favorable earlier this year with heating degree days above normal; however, the Temperature Humidity Index has been 27% below normal and 22% below 2008 levels, reducing air-conditioning loads and electric demand. We experienced only 40 hours during the summer of 2009 when temperatures were equal to or greater than 90 degrees compared with a normal expectation for approximately 125 hours. We continue to forecast a decline in weather normalized electric sales of 1.5%-2.0%. However, expectations are for the decline to be closer to the upper end of the range as sales to the residential sector are forecast to decline slightly compared with our prior forecast of flat year-over-year sales to this customer segment.

We are maintaining our forecast of PSE&G's 2009 operating earnings of $315-$335 million. The forecast continues to reflect an increase in pension expense as well as higher levels of depreciation expense.

On September 25, 2009 PSE&G updated its previous filing with the New Jersey

Board of Public Utilities (BPU) to request an increase in electric ($147 million) and gas ($106 million) revenues. This updated request reflects actual results for the six months ended June 30, 2009 as part of the forecast 2009 test year and represents an increase in electric ($13 million) and gas ($9 million) revenues over the original request.

PSEG Energy Holdings

PSEG Energy Holdings reported operating earnings of $18 million ($0.04 per share) for the third quarter of 2009 versus operating earnings of $25 million ($0.05 per share) during the third quarter of 2008.

Holdings' quarterly earnings comparisons were affected by several items. The operating profit from the generating capacity in Texas (2000 MW) declined by $0.02 per share. A decline in energy prices (in comparison to very strong pricing in the year ago period) was the primary reason for the reduction in operating earnings. Lower prices more than offset a reduction in operating and maintenance expense and the absence of financing costs following the redemption of the Texas project debt earlier in the year.

Earnings comparisons were aided by the recognition of gains on the successful termination of three cross-border leveraged leases in the quarter ($0.03 per share). Total proceeds for the sales were approximately $219 million in the quarter. Since December 2008, we have terminated 11 of these types of leases bringing in cash of approximately $675 million and reducing our cash tax potential liability by approximately $525 million. Results were also improved by a reduction in operation and maintenance expenses and a lower tax rate ($0.02 per share). We consider a recent court decision in favor of another taxpayer, with a similar lease portfolio, a positive development in the on-going management of our lease exposure.

During the quarter, an aggregate principal amount of 74% of Energy Holdings' 8.5% Senior Notes due 2011 ($368 million) were exchanged for $404 million of cash and newly issued notes from PSEG Power. The $20 million premium, after-tax, was expensed against Holdings' third quarter operating earnings ($0.04 per share). After the completion of the debt exchange, Holdings' transferred the Texas gas-fired assets to Power on October 1, 2009. The transfer will result in the movement of operating earnings associated with the Texas generating assets from Holdings' to Power for the full year. We are, as a result, reducing our forecast of Holdings' operating income for 2009 to $25-$45 million from $40-$65 million.

The following attachments can be found on www.pseg.com:

Attachment 1 - Operating Earnings and Per Share Results by Subsidiary
Attachment 2 - Consolidating Statements of Operations
Attachment 3 - Consolidating Statements of Operations
Attachment 4 - Capitalization Schedule
Attachment 5 - Condensed Consolidated Statements of Cash Flows
Attachment 6 - Quarter-to-Quarter EPS Reconciliation
Attachment 7 – Year to Date EPS Reconciliation
Attachment 8 – Generation Measures
Attachment 9 - Retail Sales and Revenues

Attachment 10 – Retail Sales and Revenues
Attachment 11 - Statistical Measures
Attachment 12 - Reconciling Items Excluded from Continuing Operations to Compute Operating Earnings

FORWARD-LOOKING STATEMENT

Readers are cautioned that statements contained in this presentation about our and our subsidiaries' future performance, including future revenues, earnings, strategies, prospects and all other statements that are not purely historical, are forward-looking statements for purposes of the safe harbor provisions under The Private Securities Litigation Reform Act of 1995. Although we believe that our expectations are based on reasonable assumptions, we can give no assurance they will be achieved. The results or events predicted in these statements may differ materially from actual results or events. Factors which could cause results or events to differ from current expectations include, but are not limited to:

• Adverse changes in energy industry, law, policies and regulation, including market structures and rules, and reliability standards.
• Any inability of our energy transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators.
• Changes in federal and state environmental regulations that could increase our costs or limit operations of our generating units.
• Changes in nuclear regulation and/or developments in the nuclear power industry generally, that could limit operations of our nuclear generating units.
• Actions or activities at one of our nuclear units that might adversely affect our ability to continue to operate that unit or other units at the same site.
• Any inability to balance our energy obligations, available supply and trading risks.
• Any deterioration in our credit quality.
• Availability of capital and credit at reasonable pricing terms and our ability to meet cash needs.
• Any inability to realize anticipated tax benefits or retain tax credits.
• Changes in the cost of or interruption in the supply of fuel and other commodities necessary to the operation of our generating units.
• Delays or cost escalations in our construction and development activities.
• Adverse investment performance of our decommissioning and defined benefit plan trust funds, and changes in discount rates and funding requirements.
• Changes in technology and increased customer conservation.

For further information, please refer to our Annual Report on Form 10-K, including Item 1A. Risk Factors, and subsequent reports on Form 10-Q and Form 8-K filed with the Securities and Exchange Commission. These documents address in further detail our business, industry issues and other factors that could cause actual results to differ materially from those indicated in this presentation. In addition, any forward-looking statements included herein represent our estimates only as of today and should not be relied upon as representing our estimates as of any subsequent date. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if our internal estimates change, unless otherwise required by applicable securities laws.

Public Service Enterprise Group (NYSE:PEG) is a publicly traded diversified energy company with annual revenues of more than $13 billion, and three principal subsidiaries: PSEG Power, Public Service Electric and Gas Company (PSE&G) and PSEG Energy Holdings.

###

EXHIBIT 14

ISO new england

Gordon van Welie
President and Chief Executive Officer

ISO NEW YORK INDEPENDENT SYSTEM OPERATOR

Stephen G. Whitley
President and Chief Executive Officer

February 4, 2009

TO: THE JOINT COORDINATED SYSTEM PLANNING INITIATIVE

ISO New England and the NYISO are pleased to participate in the Joint Coordinated System Plan (JCSP) initiative that comprises nearly all of the regional planning entities for the Eastern Interconnection. We believe this type of broad, long-term and cooperative approach to power system planning and development is important to inform federal energy policy under the new administration.

The JCSP is a highly valuable activity with respect to the collaboration it promotes among the regional planning organizations within the Eastern Interconnection and the tools it has developed. Even at this early stage of the process, the JCSP has established a framework in which to study the entire Eastern Interconnection in a single multi-regional analysis and developed a common database of information that can be used as a starting point for future studies.

The current JCSP reports on the activities undertaken in 2008, presents analyses of two wind expansion scenarios, that also assume significant baseload coal expansion, and recommends further scenarios for the group to study. ISO New England and NYISO support the JCSP recommendation to pursue additional studies and scenarios and believe these steps are required prior to reaching any broad conclusions on the need for, and scope of, development of large scale transmission. In this regard, the 2008 JCSP report cannot be viewed as a "plan" to be relied upon for decision-making purposes and we believe its publication is premature.

Our primary concern is that the report portrays its analyses to date as a basis for federal policy discussions and decisions regarding major transmission development, as it relates to the integration of renewable resources, notwithstanding the recognized need for additional work. Until additional scenarios that include the development of local resources are analyzed, we do not believe any single transmission plan can be presented as a solution to the integration of additional renewable energy resources in the United States. Conversely, there is significant value in the JCSP studies for policymakers if appropriately presented as technical scenario analysis -- coupled with the incorporation of specific planning work already underway in the various regions, including New England and New York, to integrate local renewable resources.

We also have concerns about the inclusion of issues such as cost allocation and "value based planning" considerations in the JCSP report. Since the JCSP is not itself a policy making body, we do not believe these issues should be part of the current scope nor are they appropriate for future JCSP efforts. In fact, we feel that issuing the report as it stands has the potential to constrain future collaboration, and at worst, stimulate counter-productive debate amongst regional planning organizations at it relates to these two policy areas.

In order to ensure that ISO New England's and NYISO's specific concerns are fully understood, below is a description of some of the specific activities and initiatives going on in the region and an explanation of how we believe they impact certain JCSP study assumptions and future efforts.

The New England Governors have been working actively for the past two years, not only among the six states in the region, but also in collaboration with the five eastern Canadian provinces of Quebec, Ontario, Newfoundland and Labrador, New Brunswick and Nova Scotia, to consider the integrated development of renewable and non-carbon emitting resources. Numerous proposals to develop renewables within the region (over 4800 MW in the current ISO New England Interconnection queue), including two major off shore wind projects, are being pursued by private entities. The governors and energy policymakers strongly support these developments and view them as economic development opportunities for their states -- as well as for advancing air quality and energy security goals. Recently, the governors asked ISO New England for assistance in creating a "blueprint" for developing regional energy resources and overcoming transmission barriers to enhance the energy independence of the region. Furthermore, a number of initiatives in the New England states are promoting energy efficiency and smart grid technologies. These are in addition to demand resources that are expected to comprise over 8% of the resources procured for our Forward Capacity Market for the year 2011.

New York State has put into place an aggressive policy to incent the development of a substantial level of both renewable resources as well as energy efficiency. In his recent State-of-the-State message Governor Paterson announced a further expansion of the State's efforts to achieve a "45x15" goal: i.e. a 30% level of renewable resources and a 15% reduction in the forecasted energy usage in the State by the year 2015. The energy efficiency program alone, if these goals are achieved, will reduce statewide electric demand by over 5000MW. New York already has nearly 1000MW of wind resources now in operation and the NYISO has another 8000MW in its interconnection queue, including off-shore projects totaling over 1200MW. The NYISO is working with regulators and stakeholders in New York to analyze the local transmission reinforcements that may be required to fully integrate such substantial local wind resources into the wholesale electric markets for the benefit of all consumers in the State.

With the shared geography and history of energy trading patterns between New York and New England with Eastern Canada, significant consideration is also being given to transmission options that would strengthen our access to new supplies of renewable energy—both hydro and wind—now being developed north of our states in Canada. Given these activities, it is reasonable to assume that these resources being developed in the Northeast may be deliverable to customers in our region sooner and more cost-effectively than Midwest wind resources. Given the renewable development, energy efficiency, and likelihood of new ties to Canada, the need to construct long transmission lines to the Midwest would likely be reduced and in turn overall transmission costs may be lower. We believe New England and New York policymakers and stakeholders should have the opportunity to compare such a scenario with the scenarios assumed in the current JCSP report and urge that they be included in future JCSP planning efforts.

We note that the report also assumes the development of new coal-fired generation in the Midwest without recognition of current and future restrictions on carbon emissions and their associated costs. While there is significant uncertainty about the details and timing of federal regulations for carbon, the Regional Greenhouse Gas Initiative ("RGGI") is in effect today in New England, New York and other Northeast states and its impacts on generation from coal fired resources remains to be seen. In addition, we believe it is likely that the transmission and wind project capital cost estimates contained in the initial JCSP are understated and suggest that modifications to the estimates and estimating process would help to develop a better understanding of the true costs of the expansion scenarios. Future JCSP efforts should also include the ability of stakeholders in the various regions to consider and comment on the assumptions used for these estimates.

These factors, especially the lack of recognition of important New England and New York-specific circumstances require that ISO New England and NYISO withdraw from the publication of the current

JCSP study. Despite our inability to participate in the JCSP 2008 report, we intend to continue to participate and work collaboratively towards the modifications suggested above. In order to advance the positive steps made by the participants and the Department of Energy toward joint planning initiatives, we hope that agreement can be reached on the charter, governance and scope of additional JCSP planning efforts and an improved regional stakeholder review process.

Sincerely,

Gordon van Welie
President & Chief Executive Officer
ISO New England Inc.

Stephen G. Whitley
President & Chief Executive Officer
New York Independent System Operator

cc: John Bear, MISO
Terry Boston, PJM
Nick Brown, SPP, Inc.
Daniel Fredrickson, MAPP
David Meyer, DOE
Tim Ponseti, TVA

EXHIBIT 15

PENDING LEGISLATION REGARDING ELECTRICITY TRANSMISSION LINES

Testimony of Paul A. DeCotis
Deputy Secretary for Energy
Office of the Governor
On Behalf of the State of New York

SUBMITTED TO THE UNITED STATES SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

March 26, 2009

Thank you for the opportunity to comment on this extremely important matter.

New York stands ready to work with Congress and the President to transform the electricity industry. However, current proposals being discussed have the potential to undermine New York's efforts to further develop renewable electricity resources in the northeast. Transformation of the electricity system must be undertaken with a sound and well-defined purpose and a commitment to optimizing local and regional cost-effective renewable resources first. The construction of significant amounts of renewable resources in geographic regions of the country requiring long transmission lines from remote load centers is unlikely to be the most cost-effective or practical approach to meeting the nation's renewable resource goals, should, therefore, be a last resort for developing indigenous renewable resources, improving energy diversity and security, and achieving reductions in carbon emissions.

Congress and the President acknowledge the importance of combating climate change and have proposed progressive plans designed to lower carbon emissions through the increased construction and operation of renewable energy resources. This is a laudable and timely goal, and one which the State of New York has long recognized and taken actions to achieve.

New York currently has more than 1,200 MW of wind electricity resources currently operating in the State. An additional 7,400 MW of wind resources are in the interconnection queue of the New York Independent System Operator. Potentially much more might materialize as the wind resources off the East Coast and Great Lakes are explored. A recent study suggests that wind resources located off the shores of the Great Lakes could provide more than 249,000 MW of renewable resources.[1] Hundreds of millions of dollars has been spent on the development, siting, construction and operation of these renewable resources in New York to meet its aggressive goals renewable portfolio standard (RPS) goal.

New York led the country in the promotion of renewable energy resources through the implementation of its RPS in 2004. New York is on track to provide 25 percent of electric energy use in the State from renewable resources by 2013. Governor Paterson has further challenged New York to stretch the goal to 30 percent of electric energy use provided by renewable resources by 2015. To date more than 3.5 million MWh of annual renewable energy has been contracted to be delivered to the residents of New York through this

[1] http://greengold.org/wind/documents/88.pdf

program. Contracts awarded under the program to date, using State and ratepayer funds, have amounted to $559 million.

In 2003, New York, along with nine other states from the Northeast and Mid-Atlantic developed and implemented the first mandatory cap-and-trade program in the United States to reduce greenhouse gas emissions through the Regional Greenhouse Gas Initiative (RGGI). Initiated and led by New York, the program encourages reductions in carbon dioxide (CO_2) emissions by setting emission limits for electric power plants, creating CO_2 allowances and establishing a CO_2 allowance auction process. RGGI's cap-and-trade program encourages regional electric generators and load serving entities to plan for and invest in lower carbon alternatives for electric production. Proceeds from the auction are in turn used for low-carbon electric production resources, including wind resources, transportation, energy efficiency, and support of other measures that reduce CO_2 across all sectors of the economy.

The federal legislative proposals, if not modified, could hinder the ability of states to ensure their consumers are receiving clean energy most economically. Moreover, even if the proposals are modified, failure to carefully designate renewable energy zones and allocate costs of transmission facilities, as contemplated by the legislative proposals, will likely, in the end, have a chilling effect on the development of renewable energy in some regions of the country. In addition, states that are not part of a renewable energy zone, but have been advancing policies, such as a RPS or CO_2 cap-and-trade, might be financially harmed as the once robust investment by renewable energy developers, and the associated industry that supports them, move out of state to other states that are part of these zones. Congress should work toward a solution for reducing CO_2 and other greenhouse gas emissions in a manner that does not cripple the robust renewable energy industry that some states have already developed.

Inter-regional transmission plans that provide a vision for build-out of the nation's transmission system are necessary before efficient use of renewables and siting of required transmission can be accomplished. The development of these plans must be open, transparent and provide meaningful governance on the conduct of studies. Provisions must be included to insure that plans respect all applicable national and regional electricity system reliability criteria.

States are best suited, in the first instance, to provide a thorough review of an application for a certificate to construct an electric transmission facility. The wealth of state experience in electric transmission siting and the efficiencies to be gained by the Federal Energy Regulatory Commission (FERC) from allowing the states to develop the record supports allowing states to proceed first in determining whether to grant a certificate to a transmission developer. In addition, the states should be given at least two years to develop the necessary and extensive record and to either deny or certificate a project before FERC considers assuming siting authority.

Cost allocation is a complicated issue that can undermine the good intentions of the legislation. The FERC should be directed to establish a proceeding that examines the differing approaches to cost allocation and results in rules that balance the many regional interests involved in allocation. Any cost allocation method, however, should be established for a transmission project proposed under either of these legislative proposals, prior to the FERC rending a determination on their application for siting.

New York's concerns related to the designation of renewable energy zones and the planning, siting and cost allocation for electric transmission facilities are further developed below.

Designation of Renewable Energy Zones

Designation of renewable energy zones should not disadvantage one geographic area of the country in favor of another. If not done carefully, designation of renewable energy zones could disadvantage New York's more than 1,200 MW of wind resources. The additional 7,400 MW of wind resources in the interconnection queue of the New York Independent System Operator, the possible 249,000 MW of off shore resources, as well as the numerous construction jobs and jobs associated with the operation and maintenance of future wind resource projects may fail to materialize if developers determine that their projects would obtain an advantage from siting in renewable energy zones.

Consequently, all renewable resource capability of a state or geographic area should be examined. The winds of the Great Plains, solar of the Southwest, hydroelectric resources of Canada, offshore winds of the East Coast and the Great Lakes as well as various wind rich resources in the Northeast should all be given equal opportunity to contribute to the renewable goal, interconnect to the electric grid and operate in the electric markets. Senator Reid's bill might ultimately stall renewable energy projects in geographic areas of the country that are not included in a renewable energy zone. The areas not designated as renewable energy zones will likely experience a dramatic reduction in regional investment in renewable energy as investors and developers seek out the advantages of being located in a renewable energy zone.

The most cost-effective way to reduce dependence on imported and fossil energy and to reduce carbon emission is to first optimize local resources available. For example, construction of a transmission line to bring lower-cost Canadian hydropower to New York might be the most cost-effective solution for reducing carbon emissions in New York, rather than building an exceptionally long electric transmission line from areas west of New York to bring both renewable, and potentially high fossil fuel-based energy to the State. The consequences of designating a renewable energy zone must be carefully evaluated for both the zone itself and for areas not so designated.

Interconnect-Wide Green Transmission Grid Project Planning

Senator Reid's bill calls for the certification by FERC of a regional planning entity that will be solely responsible for the development of an interconnection plan for connecting all renewable energy resources in a renewable energy zone to the electric transmission grid. One or more planning entities will be designated, according to the bill, for each interconnection. The Eastern interconnection covers all or portions of 38 states plus the District of Columbia, and several provinces in Canada. This expansive geographic region contains a diverse population of energy resources and transmission facilities along with varying environmental, business and social interests. To simply designate one (or even two) regional planning entities for the entire interconnection would create a very difficult challenge to integrate the vast diversity of the region.

Transmission planning is currently conducted at the regional and sub-regional level. Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), working with utilities and state authorities owning transmission assets, load-serving entities and consumer groups, carefully evaluate the needs of the electricity grid from both a reliability and economic standpoint along with considering environmental public policy goals, and develop long range plans for the system. Moreover, transmission owners independently and state utility commissions continually evaluate the electric grid to determine where best to provide upgrades and new facilities for the electric transmission system. Taking this essential responsibility from the organizations best suited to perform transmission planning and vesting that responsibility in one or two interconnection-wide planning entities would invite inefficiency at best, and cause reliability problems at worse.

There is no need for Congress to reinvent the wheel. If transmission planning for the interconnection of renewable resources is necessary to ensure the continued expansion of renewable resource capacity, then perhaps the most efficient course of action for Congress is to mandate that FERC direct the RTOs and ISOs to conduct such planning. Where integrated RTO and ISO planning must occur, FERC should direct such planning to take place.

If interconnection-wide planning is pursued, legislation must include requirements for balanced, transparent governance of the effort that includes representation for all covered planning authorities and states. Recent attempts at interconnection-wide planning in the east have shown that parochial interests of those in control of planning studies dictate planning parameters. Furthermore, all reliability rules and siting constraints must be respected in the development of the plan. New York has the legislative right to impose reliability standards more stringent than national standards and must be accommodated in any planning interconnection-wide process. New York also has long standing regulations that limit electro-magnetic field levels related to transmission design that must be respected by the planning process.

Federal Siting of Transmission

The legislative proposals preempt either outright, or after an ambiguous period of time, the state's authority to certificate electric transmission lines. In the event of preemption, the proposals authorize FERC to certify electric transmission projects, grant transmission owners the power of eminent domain, and perform all necessary environmental reviews.

The states have unique experience to certificate an electric transmission line and have been performing this function since the inception of the electric transmission system. Knowledge of environmentally sensitive local areas, understanding of the unique characteristics of the local electricity transmission system, and familiarity with the public interest all favor allowing the state to be first with the certification process. Moreover, issues related to transmission siting can vary depending on the geographic area the facility is located. For example, siting electric transmission facilities in rural areas, which may include government-owned land, presents a far different set of considerations than siting the same facilities in densely populated urban areas. Developing a record, which at times can be thousands of pages of testimony and thousands of exhibits, is a daunting task that the states are well equipped and expertly trained to undertake. It would be more efficient if states are allowed to develop the record and conduct the siting proceeding in the first instance and reserve for FERC a backstop role to review the state determination. State public utility commissions possess significant experience and have expertise in evaluating electric transmission projects. Given the wealth of state experience in electric transmission siting and the efficiencies that may be gained by the Commission, Congress, should it pursue federalizing electric transmission siting, should at a minimum give the states two years at least to evaluate and either deny or certificate a project before preempting the states. This process has worked well in the recent siting of the multi-state TRAIL transmission facility in the PJM territory.

Both legislative proposals are also sketchy on the type of analysis that FERC must undertake in order to grant a certificate. Furthermore, the interconnection plan to be developed by the regional planning entity is devoid of any requirement that cost-effective local resources should be considered. If a massive build-out of electric transmission facilities is going to be undertaken in the country, ratepayers of this nation deserve a system that brings renewable energy to geographic areas in a cost-effectively. Assuming that FERC has jurisdiction over transmission siting for renewable energy zones, a cornerstone of FERC's evaluation of a project should be whether the costs, both economic and environmental, of the transmission facility outweigh the benefits of construction of such a facility, including overall reduction in emission levels. Calculation of benefits can and should consider more than the economic or reliability benefits that might be provided by the project. The benefits provided by increasing fuel diversity, greater energy independence and security, and improving the environment can all be factored into the calculation of project attributes to determine if there is a public benefit from the siting of the new facility.

FERC must also consider the physical operation of the electric transmission system and other resources that might use the new transmission facilities. For example, carbon emissions might increase nationally as a result of coal plants using the transmission facility during periods when renewable resources are not operating. These reasonably likely scenarios should also be factored into the analysis of the benefits and costs provided by a project.

Cost Allocation of Transmission Project Costs

Cost allocation, an aspect of both Senator Reid's and the Majority's Draft Proposal must be done right. Poorly crafted cost allocation rules can undermine the overriding goal of renewable development. Cost-allocation principles need to be in place before any specific project enters the siting process, be it at the state or federal level. Entities that will be held responsible for the project costs must be aware of the proceeding and the potential impacts that could result from the case. For example, charging only the beneficiaries of a project for the costs introduces the complication of defining who the beneficiaries are and by how much they benefit so that costs can be allocated proportionate to the benefits. On the other hand, socialization of costs can potentially create inequities as some costs will have to be paid by entities that may not benefit at all from the project. Rather than specify a cost- allocation methodology in legislation, FERC should be charged with establishing appropriate cost-allocation principles through an open proceeding where the differing approaches can be examined and regional interests can be balanced.

Conclusion

New York supports a national energy agenda that moves the nation toward greater energy independence and diversity, development of indigenous energy resources and the jobs associated with it, carbon emission reductions, and minimizes to the greatest extent the costs to consumers for attaining both goals. We stand ready to work with Senator Reid, Senator Bingaman, and the members of this Committee to reach these goals.

EXHIBIT 16

Massachusetts Rhode Island Delaware Maine Maryland

New Hampshire New Jersey New York Vermont Virginia

May 4, 2009

The Honorable Harry Reid
Majority Leader
U.S. Senate
Washington, DC 20510

The Honorable Mitch McConnell
Minority Leader
U.S. Senate
Washington, DC 20510

The Honorable Nancy Pelosi
Speaker
U.S. House of Representatives
Washington, DC 20515

The Honorable John Boehner
Minority Leader
U.S. House of Representatives
Washington, DC 20515

Dear Senator Reid, Senator McConnell, Speaker Pelosi, Representative Boehner,

As Governors from Northeast and Mid-Atlantic states, we applaud your support for renewable energy and its role in enhancing clean energy job creation, increasing our energy security and curbing greenhouse gas emissions.

We write to encourage you to support strong new federal policies to promote wind resources. In addition to recognizing the potential for wind resources in the Midwest, we believe that the wind resources of the Eastern seaboard states – both onshore and offshore wind – represent one of our nation's most promising yet underdeveloped source of renewable energy. At the same time, we must express our concern about the significant risks posed by recent proposals regarding transmission that we believe could jeopardize our states' efforts to develop wind resources and inject federal jurisdiction into an area traditionally handled by states and regions.

Significant onshore or offshore wind projects have been proposed or planned for almost all of the Northeast and Mid-Atlantic states. Several of our states already have significant land-based wind projects installed or well underway and have established aggressive wind development goals. Moreover, the waters adjacent to the East Coast hold potential for developing some of the most robust wind energy resources in the world – enough wind potential to meet total U.S. electricity demand, as Interior Secretary Ken Salazar has recently pointed out. Congress should put its full support behind the development of these resources.

Current legislative proposals focused on transmission, in contrast, would designate national corridors for transmission of electricity from the Midwest to the East Coast, with the costs for that transmission allocated to all customers. While we support the development of wind resources for the United States wherever they exist, this ratepayer-funded revenue guarantee for land-based wind and other generation resources in the Great Plains would have significant, negative consequences for our region: it would hinder our efforts to meet regional renewable energy goals with regional resources and would establish financial conditions in our electricity markets that would impede development of the vast wind resources onshore and just off our shores for decades to come. In addition, the legislative proposals for selective federal subsidy for certain land-based wind resources paired with the practice of dispatching the lowest cost available generation resource could result in surplus transmission capacity or artificially inflated energy prices for Midwest renewables being paid by east coast ratepayers. Such an outcome would have negative consequences for consumers, regional energy sufficiency and the environment. Moreover, it is well accepted that local generation is more responsive and effective in solving reliability issues than long distance energy inputs.

Land-based wind energy projects, which have already proven themselves economical in the Northeast, must have the chance to move forward. And while offshore wind installation costs currently exceed those of onshore installations, these resources are much closer to our load centers and research and development efforts focused on reducing costs and improving reliability promise to make offshore wind competitive with Midwest wind farms on a delivered cost of power basis. As regional onshore projects move forward and offshore wind moves into commercialization in the United States, they all must have the opportunity to compete on an even playing field with on-shore, yet remote, sources of power from the Midwest and not be disadvantaged by upfront transmission subsidies.

If transmission is to be addressed in energy legislation at all, we believe Congress should focus its attention on regional solutions. In our regions, this means continuing to pursue planned wind and other renewable resources within our competitive energy markets framework. For offshore wind, this means a new offshore wind transmission backbone to facilitate the interconnection of offshore renewable energy resources to major load centers along the East Coast. Development of this offshore network will require the attention of the Department of Energy, the Minerals Management Service (MMS) and the Federal Energy Regulatory Commission (FERC), as part of an Outer Continental Shelf energy resource development plan.

In our view, legislation to promote renewable energy resources on a fair, equitable, and efficient basis should, at a minimum:

- Create strong federal energy efficiency and renewable energy incentives that are simple, transparent and technology neutral – and capitalize on more than a decade of successful direct experience by many states in developing strong efficiency and renewable energy markets;

- Consider new market mechanisms such as regional procurements for renewable energy in the form of long-term power purchase agreements – again, allowing all renewable generation interests to compete on the basis of total cost of power delivered to load centers;

- Encourage that state and regional planners along the Atlantic coast develop a plan within and across regions to accommodate growing availability of onshore wind resources and to establish an offshore wind transmission regime, including new FERC policies tailored to the special circumstances of offshore wind and expedited siting review for offshore lines in federal waters and their interconnection to coastal load centers with appropriate state involvement.

- Encourage FERC and NERC to support and facilitate robust planning within regional transmission organizations that provides and promotes local renewable resources integration and preserves local oversight and review.

- Evaluate whether expanding the federal Investment Tax Credit would be a more effective, simpler, and technology neutral mechanism for promoting renewable energy development across the country than a focus on transmission, which tends to support remote onshore wind, but disadvantage nearby offshore wind.

Thank you for your attention to this critical issue.

Sincerely,

Governor Deval Patrick
Massachusetts

Governor Donald L. Carcieri
Rhode Island

Governor Jack Markell
Delaware

Governor John Baldacci
Maine

Governor Martin O'Malley
Maryland

Governor John H. Lynch
New Hampshire

Governor Jon S. Corzine
New Jersey

Governor David A. Paterson
New York

Governor James H. Douglas
Vermont

Governor Timothy M. Kaine
Virginia

cc: Chairman Jeff Bingaman
Ranking Member Lisa Murkowski
Chairman Henry Waxman
Ranking Member Joe Barton
Secretary Steven Chu
Secretary Ken Salazar
Honorable Carol Browner

EXHIBIT 17

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

DELIVERABILITY

QUESTION:
To meet all the deliverability standards PJM & PSE&G have adopted supplemental to NERC reliability standards, must any capacity resource within PJM be deliverable to any other area within PJM? If not, please provide an example that demonstrates otherwise. If so, please explain.

ANSWER:
The PJM deliverability criteria is used to define the critical system condition under which compliance with the NERC Standards is tested. PJM, as the Planning Authority designated under the Standards, is required to define such critical system condition. Every PJM capacity resource is required to be demonstrated as deliverable, in aggregate with all other PJM capacity resources, to the aggregate of PJM load, per the PJM deliverability procedures which are described in PJM Manual 14-B at http://www.pjm.com/documents/~/media/documents/manuals/m14b.ashx. Individual resources are not required to be demonstrated to be deliverable to individual locations within PJM.

EXHIBIT 18

RESPONSE TO STOP THE LINES
REQUEST: STL-JACOBER-4
WITNESS(S): JACOBER

SUSQUEHANNA-ROSELAND

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GIS

QUESTION:
Direct, p. 3 & p. 5, define "GIS" switching station and explain the term "GIS."

ANSWER:
As indicated on page 5 of Richard I. Jacober's Direct Testimony, "GIS" in the context of switching station equipment means Gas Insulated Switchgear. The technology is used to reduce the size of the footprint required to install the needed switching station equipment. A GIS switching station can be installed to have all of the same types of electrical components as an open-air switching station; however, the footprint size of the GIS switching station will be smaller. The reason that the GIS switching station can be built in a smaller footprint is the electrical equipment components (buses, circuit breakers, disconnect switches, etc.) are enclosed in a tube that is filled with SF6 gas. Although the GIS technology provides benefits of a reduced footprint, it also is more costly than open-air equipment.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

GIS STATION

QUESTION:
Direct, p. 3 & 5, is it correct that the GIS switching station will utilize hexafluoride (SF6)? What is impact of SF6 leakage? What prevention and mitigation is planned?

ANSWER:
Yes, the GIS equipment is filled with SF6 (sulfur hexafluoride) gas. IEEE and IEC design standards for GIS equipment require that the GIS equipment be designed to limit gas leakage rates to less than 1% per year. Manufacturers of GIS equipment indicate that although the standards require that GIS leakage rates be less than 1% per year, the manufacturing and gas compartment sealing processes presently used actually limit gas leakage rates to values well below the 1% per year limit. To assist in preventing gas leakage the equipment is designed and manufactured with multiple gas sections that are isolated from adjacent gas sections to limit the potential volume of gas leakage if a leak would occur. In addition, manufacturer's install gas density monitors in each gas section to consistently monitor each gas section and to sense any changes in the gas system. In addition, PSE&G practices very stringent SF6 gas handling policies which include SF6 gas reclamation and recycling activities during equipment maintenance activities.

EXHIBIT 19

RESPONSE TO MUNICIPAL INTERVENORS
REQUEST: MUNIS-GENERAL-22
WITNESS(S): MCGLYNN
PAGE 1 OF 1
SUSQUEHANNA-ROSELAND(2)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

RELIABILITY VIOLATIONS

QUESTION:
How have PJM/PPL/PSE&G's expected reliability violations compared to reliability violations during normal operations when no additional transmission capacity that would directly mitigate the reliability violations has been installed during the intervening time period?

ANSWER:
It is not clear what is meant by "normal operations". PJM assumes this request to ask if PJM has observed any transmission limitations in PPL/PSE&G in the past and would PJM expect to do so between now and 2012. See the response to Munis-1-21 for past off-cost operations. Past PJM RTEP analyses have shown increasing flows on the transmission facilities identified as reliability criteria violations beginning in 2012.

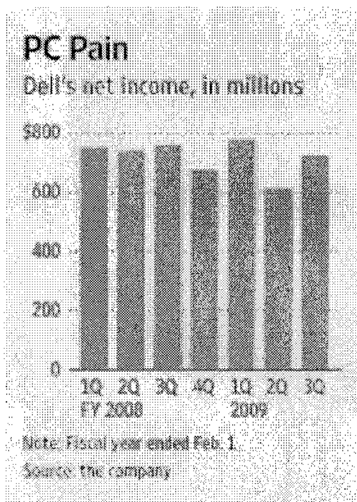
EXHIBIT 20

- THE WALL STREET JOURNAL.
- WSJ.com

- BUSINESS
- NOVEMBER 21, 2008

Surprise Drop in Power Use Delivers Jolt to Utilities
By REBECCA SMITH

An unexpected drop in U.S. electricity consumption has utility companies worried that the trend isn't a byproduct of the economic downturn, and could reflect a permanent shift in consumption that will require sweeping change in their industry.



Numbers are trickling in from several large utilities that show shrinking power use by households and businesses in pockets across the country. Utilities have long counted on sales growth of 1% to 2% annually in the U.S., and they created complex operating and expansion plans to meet the needs of a growing population.

"We're in a period where growth is going to be challenged," says Jim Rogers, chief executive of Duke Energy Corp. in Charlotte, N.C.

The data are early and incomplete, but if the trend persists, it could ripple through companies' earnings and compel major changes in the way utilities run their businesses. Utilities are expected to invest $1.5 trillion to $2 trillion by 2030 to modernize their electric systems and meet future needs, according to an industry-funded study by the Brattle Group. However, if electricity demand is flat or even declining, utilities must either make significant adjustments to their investment plans or run the risk of building too much capacity. That could end up burdening customers and shareholders with needless expenses.

To be sure, electricity use fluctuates with the economy and population trends. But what has executives stumped is that recent shifts appear larger than others seen previously, and they can't easily be explained by weather fluctuations. They have also penetrated the most stable group of consumers -- households.

Dick Kelly, chief executive of Xcel Energy Inc., Minneapolis, says his company, which has utilities in Colorado and Minnesota, saw home-energy use drop 3% in the period from August through September, "the first time in 40 years I've seen a decline in sales" to homes. He doesn't think foreclosures are responsible for the trend.

Duke Energy Corp.'s third-quarter electricity sales were down 5.9% in the Midwest from the year earlier, including a 9% drop among residential customers. At its utilities operating in the Carolinas, sales were down 4.3% for the three-month period ending Sept. 30 from a year earlier.

American Electric Power Co., which owns utilities operating in 11 states, saw total electricity consumption drop 3.3% in the same period from the prior year. Among residential customers, the drop was 7.2%. However, milder weather played a role.

Utility executives question whether the recent declines are primarily a function of the broader economic downturn. If that's the case, says Xcel's Mr. Kelly, then utilities should continue to build power plants, "because when we come out of the recession, demand could pick up sharply" as consumers begin to splurge again on items like big-screen televisions and other gadgets.

Some feel that the drop heralds a broader change for the industry. Mr. Rogers of Duke Energy says that even in places "where prices were flat to declining," his company still saw lower consumption. "Something fundamental is going on," he says.

Michael Morris, the chief executive of AEP, one of the country's largest utilities, says he thinks the industry should to be wary about breaking ground on expensive new projects. "The message is: be cautious about what you build because you may not have the demand" to justify the expense, he says.

Utilities are taking steps to get a better understanding of the cause. Some are asking customers who reduced usage to explain what is influencing them. Xcel and other utilities, for example, have been running environmentally focused campaigns to urge consumers to use less energy recently, a message that might be taking hold.

Power companies are also questioning the reliability of the weather-adjustment models they use to harmonize fluctuating sales from quarter to quarter. "It's more art than science," says Bill Johnson, Chief Executive of Progress Energy Inc., Raleigh, N.C.

If the sector is entering a period of lower demand -- which could accelerate further if the automotive sector collapses -- many utilities will have to change the way they cover their costs.

Utilities are taking a hard look at the way they set rates and generate profits. Many companies are embracing a new rate design based on "decoupling," in which they set prices aimed at covering the basic costs of delivery, with sales above that level being gravy. Regulators have resisted the change in some places, because it typically means that consumers using little energy pay somewhat higher rates.

Write to Rebecca Smith at rebecca.smith@wsj.com