Words: 4,095
March 16, 2004

DRAFT

4. Financial Performance and Investment

1. Introduction

Within two weeks of the August 14, 2003 blackout the Wall Street Journal reported

> "The nation's electric power industry…is preparing to launch a public-education campaign to help it raise $100 billion from investors, governments and consumers to upgrade the nation's power grid"[1]

The estimate seemed plausible to the press given the Federal Government's oft repeated concerns with grid investment. But, within three months the Public Utilities Fortnightly published an article saying

> " We don't know what caused the …blackout but somehow we know that our transmission system needs $50 billion to $100 billion in investment and upgrades. And utilities need higher returns…The reality is that we aren't short $50 billion or $100 billion…the study said to support that conclusion doesn't do the job."[2]

For the foreseeable future, Federal and state policy makers will remain at the center of these controversies. They will be asked to decide: how much investment is enough? Where should investments be made? What returns are necessary to elicit those investments? Who should pay? What charges are reasonable? To make informed decisions policy makers require data to guide their judgments.

FERC is charged with ensuring "just and reasonable" prices for power in interstate commerce. State regulators continue to be deeply involved in transmission regulation in most states. They effectively regulate transmission costs and prices for "internal transactions" and also control siting and eminent domain.

FERC has long collected capital and operating cost data from investor owned utilities (IOUs). FERC uses the information to ensure delivered electricity tariffs bear a reasonable relation to costs. EIA complements the FERC collections with less detailed reports from the other generation and transmission owners to produce industry wide totals. Both Agencies focus on generation and distribution data because transmission's costs are a small portion of total costs. In 2000, for example, major public electricity utilities' transmission operating costs were only 4% of their total operating costs.[3] Transmission plant was 11% of total electric plant in service.[4] In a cost of service world

[1] Failka, John J., "Power Industry Sets Campaign to upgrade Grid," *Wall Street Journal, August* 25, 2003 page A3.
[2] Huntoon, Steve and Metzner, Alexandra, "The Myth of the Transmission Deficit," Public Utilities Fortnightly, November 1, 2003, page 28
[3] EIA, Electric Power Annual 2001, Table 8.3, page 51.
[4] Available at www.eia.doe.gov/cneaf/electricity/public/t11p01p1.html . Appears as Table 11, Electric Utility Plant for Major U.S. Publicly Owned Generator Electric Utilities at End of Period, 1996-2000.

where all costs are bundled together to form a single price for delivered electricity, transmission's specific costs are unimportant.[5]

FERC's restructuring of the electricity industry has broadened its perspective beyond cost recovery to the economics of transmission. Order 2000 in establishing Regional Transmission Organizations (RTOs) notes

> "effective and efficient RTOs… [are]… dependent in large measure on the feasibility and vitality of the stand-alone transmission business."[6]

The difficulty in obtaining financial data showing "vitality" is that transmission is rarely a stand-alone business. Almost all investor owned utilities derive most of their total revenues from supplying bundled power (energy, transmission and services) to native customers at state-regulated prices. Separate transmission prices and revenues for internal customers do not exist. Merchant transmission companies only sell transmission but they are miniscule. Cooperatives and public power are not in the business of selling transmission. The only "market like" transmission prices are those customers pay for wheeling power across a system. Wheeling revenues, however, are a very small amount of total revenues.

2. Measures of Financial Performance and Investment

Unlike reliability, there is considerable agreement about how financial performance should be measured and how financial data should be interpreted. Even so there are long standing debates about how to obtain better agreement between accounting and economic values and how to value uncertain prospects and illiquid assets. FERC requires utilities it regulates to use the Uniform System of Accounts. These accounts are more detailed accounts and require far more disclosure that is usual for publicly traded companies.

FERC collects financial and operating data annually from major privately owned electric utilities on the FERC FORM 1: *Annual Report of Major Electric Utilities, Licensees and Others.*[7] FERC requires utilities under its jurisdiction to submit the following schedules for the calendar year

1. Comparative Balance Sheet
2. Statement of Income
3. Retained Earnings
4. Statement of Cash Flows
5. Notes to Financial Statements.

---

[5] The transmission grid's relatively small costs do not mean that its efficient operation and development is unimportant. Efficiency reduces costs in the short run and ensures that the grid is not a drag on economic growth and competition. Efficient grid operation generally means its services are priced at marginal cost. Efficient development means that all potential investments are considered and those whose net benefits, adjusted for risk and timing, are greatest are made. The need to consider all relevant investments is easy to overlook. Line congestion, outages and other transmission problems may best be solved by investments in distributed generation, demand side management or other alternatives to transmission facilities.

[6] FERC, Regional Transmission Organizations, Order 2000, 65 Fed. Reg. 809(June 6,2000), FERC Stats.& Regs. At 31, 170.

[7] FERC has proposed to collect quarterly financial data on a new Form No. 6-Q. See Federal Regulatory Commission, Quarterly Financial Reporting and Revisions to the Annual Reports, 18CFR Parts 141. 260,357 and 375, June 26, 2003.

All the are data are entered on the form following the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act.

The transmission revenues reported on Form 1 are those for wheeling power for others. The FERC Form 1 specifically identifies 15 subcategories of transmission operating and maintenance costs (page 321) and the book value (acquisition cost) of nine subcategories of the transmission plant and equipment (page 206). The form also identifies the calendar year additions to transmission plant and equipment. The revenues from transmission of electricity for others (Account 456) are broken down into energy charges, demand charges and other charges. FERC has proposed to require explicit reporting of purchases and sales of ancillary services.[8] Debt, stockholder equity, taxes and miscellaneous expenditures are listed and described in detail.

In addition to giving FERC information for approving company tariffs and investments, FERC FORM 1 is used by financial analysts to assess private utility's short-term solvency, its financial risk, long-term viability and returns to investment and investors.

Text Box: Ratio Analysis

Financial analysts often examine operating efficiency ratios and operating profitability ratios to better understand how firms generate profits. In a typical application a financial analyst would decompose return on equity (ROE which is net income divided by equity) into components to highlight differences among firms. The DuPont identity is a popular decomposition. The DuPont identity expresses FOE as the product of profit margin, total asset turnover, and financial leverage, i.e.,

$$\text{Return on Equity} = \begin{pmatrix}\text{Net Profit}\\ \text{Margin}\end{pmatrix} \times \begin{pmatrix}\text{Total Asset}\\ \text{Turnover}\end{pmatrix} \times \begin{pmatrix}\text{Financial Leverage}\\ \text{Multiplier}\end{pmatrix}$$

$$= \left(\frac{\text{Net Income}}{\text{Sales}}\right) \times \left(\frac{\text{Sales}}{\text{Total Assets}}\right) \times \left(\frac{\text{Total Assets}}{\text{Equity}}\right)$$

An example of two hypothetical firms both earning 12% per year on equity illustrates how these decompositions aid financial analysis.

Firm	Net Profit Margin	Asset Turnover	Financial Leverage Multiplier	ROE
A	8%	2.0	0.75	12%
B	3%	1.0	4.00	12%

[8] Op cit, Appendix B.

While both firms have the same ROE (12.0%), the underlying means of generating ROE are very different. Firm A has high net profit margins, high turnover, and low financial leverage. Firm B has low net profit margins, low operating efficiency, but has used financial leverage to increase its return. The DuPont identity indicates that that Firm A is stronger than Firm B, in terms of profitability, efficiency and risk.

EIA annually collects an abbreviated version of the FERC 1 , the EIA 412, from publicly owned utilities (municipalities, political subdivisions, States and Federal entities). EIA requires the following schedules for the respondent's fiscal year

1. Balance Sheet
2. Income Statement
3. Electric Plant
4. Taxes, Tax Equivalents, Contributions, and Services During the Year
5. Sales of Electricity for Resale
6. Electric Operation and Maintenance Expenses.

Like FERC, EIA collects data on wheeling revenues. EIA encourages, but does not require, respondents to use the Uniform System of Accounts. Analysts use the data to compare the operations of publicly owned and investor owned utilities and to evaluate potential public exposure to their debt. EIA uses the data to complete its statistical description of the industry.

No system of accounts, no matter how conscientiously followed, captures all economic values perfectly. Transmission equipment, for example, is very long lived making book values poor measures of either replacement or market value. Likewise most utility land holdings were acquired long ago. Rights of way are also valuable assets originally obtained under the implicit threat of eminent domain. Market values for them are unavailable.

3. Restructuring's impacts on relevant financial data

FERC Order No. 888 required all public utilities that own or control interstate transmission to functionally unbundle wholesale power services. Functional unbundling requires the public utility to

(1) Take transmission services under the same tariff as do others;
(2) Post separate rates for wholesale generation, transmission and ancillary services: and
(3) Rely on the same information system that its customers use.

FERC considered but did not require divestiture of transmission from generation and institutional changes to achieve functional unbundling. FERC did not require public utilities to spin off transmission into standalone business units.

With the growth of independent power suppliers, the transmission business has become something of a mongrel. The transmission owning utility earns revenues by charging others posted rates for wholesale transmission and services; it charges itself for its own wholesale sales at the same rates. The utility neither posts transmission rates for bundled retail sales nor does it charge itself for transmission. Instead, the charges for transmission are bundled with the price of delivered power. FERC has not required “financial unbundling” by line of business. Consequently it is not possible to know total revenue or to know if the utility is charging nondiscriminatory rates for transmission to retail customers.

Since reasonable transmission and service rates for others are partially defined based on costs, sharp distinctions between transmission’s costs and those of distribution and generation are important under restructuring. The FERC 1 allows respondents to determine their own boundaries. That makes meaningful comparisons across transmission providers difficult, if not impossible.

An implicit assumption behind financial accounts is that each company’s revenues and costs capture the major economic benefits and costs. Before system interconnections and large power flows across systems became important, integrated utility costs and benefits were essentially the same as total costs and benefits, i.e., they were internal to the utility. The same identification is dubious in a restructuring transmission industry.

An economically important external cost occurs when one system’s operations load lines in other systems to the point that the impacted system cannot use their lines much as they otherwise would. Lines loaded to their security limits are congested. Electricity flows everywhere in a connected AC system in response to relative line resistance and the locations and amounts of generation and consumption. How an operator decides to dispatch generators, secure imports or otherwise meet (or refuse to meet) demand can cause lines to be congested far outside his system’s boundaries. Faced with line congestion, operators can only meet their customers’ increased demands by running more costly, but better situated, generators. These additional costs show up in the books of the impacted system; costs are artificially lower in the books of the system causing the congestion.[9]

Congestion costs within individual systems are being measured and valued (inconsistently) in a few parts of the country. Chapter 5 contains a discussion of congestion costs and revenues. These costs are not identified on the FERC 1.

FERC’s 2000 Regional Transmission Organization order would bring together many transmission providers into a few regional transmission organizations. In a regional setting individual companies cannot be held solely responsible for the costs borne by customers. A particular company may experience abnormally high costs because it made expenditures that lower overall regional costs; another may have artificially low costs because it exploits “beggar thy neighbor” opportunities.[10] In a restructured industry the costs of a Regional Transmission Organization as a whole, not just its individual companies reporting on the FERC 1, would be relevant to costs, tariffs and investments.

---

[9] Operating decisions which relieve congestion and lower costs in other areas are not compensated either.

[10] One role of RTOs is to internalize significant external costs and to manage them on an equal footing with each systems cash costs.

Restructuring has also motivated public policy concern about the level and kinds of investment being made in the grid. The FERC 1 collects data on transmission plant and equipment and additions to plant and equipment. Unlike the national income accounts, the "additions" data is not restricted to acquisitions of new equipment. Plant and equipment refers to the purchase price of any qualifying good, including land, regardless of its age. When a utility sells old equipment at above net book value to another reporter, the data shows net additions, though nothing has changed on the ground. Generators have sold for much more than net book value in the recent past. Net additions (after subtracting land acquisitions) may, or may not be a good proxy for the economic concept of investment.

As mentioned in Chapter 3, power flows are more volatile and likely to change course more than before restructuring. In this environment, investment in system metering, communication, computation and control are critical to improving reliability when power flows are more volatile and changing. These classes of capital are not identified on the FERC 1.

Restructuring has also brought about transmission investments from new entities. Merchant transmission companies are one example. As discussed in the following chapter, new independent generators are making significant grid investments as a condition of connecting to the grid. Since FERC does not require merchants and independent generators to make detailed financial reports to FERC, their investments may not be recorded in official data.

In a fully restructured environment, financial data for evaluating the economics of transmission would include:

1. Stand alone financial accounts for the transmission business.
2. Estimates of external costs and benefits, especially the value of congestion.
3. Integration of individual transmission provider accounts to the appropriate RTO.
4. Complete investment totals that include an identification of those undertaken for grid control.

4. Official Transmission Financial Data

Standalone accounts: Except for those few utilities that are strictly dedicated to transmission, it is not possible to construct stand-alone financial statements for transmission from official data. Both the EIA 412 and the FERC 1 identify transmission sold (purchased) from others. FERC has proposed that utilities report the grid's sales (purchases) of ancillary services. Neither form reports transmission and services provided to the utility's own generators. As a consequence it is not possible to calculate transmission's returns on either investment or equity. Ratio analysis of the kind sketched above cannot be done. Official data does however indicate how restructuring has affected revenues from transmission sells to others.

Transmission Revenues: Transmission for others, called wheeling, has grown since the start of restructuring (1996) in some regions and declined in others. Nationwide volumes and revenues more than doubled over the period 1996-2001. Tables 4-1 and 4-2 show net wheeling, ("wheeling for others" minus "wheeling by others") volumes and revenues for the United States and for utilities located in the North Central States (ECAR), Midwest (MAPP) and the West (WECC).

Table 4-1. Gross Volume of Wheeling in Three Regions (billion kWh)

Year	ECAR	MAPP	WECC	United States
1993	28.4	14.1	74.6	268.6
1994	26.2	16.5	65.2	252.6
1995	29.7	15.5	64.4	264.2
1996	55.2	15.2	69.7	303.8
1997	61.7	17.2	67.4	326.4
1998	67.6	18.7	73.7	373.3
1999	67.9	22.2	76.9	370.1
2000	85.4	18.8	87.1	490.5
2001	157.3	18.8	112.1	671.8
2002	159.4	13.8	105.5	705.8

Sources: EIA staff assembled this table from RDI's PowerDat compilation of the EIA 412, FERC 1 and RUS7 and 12 data.

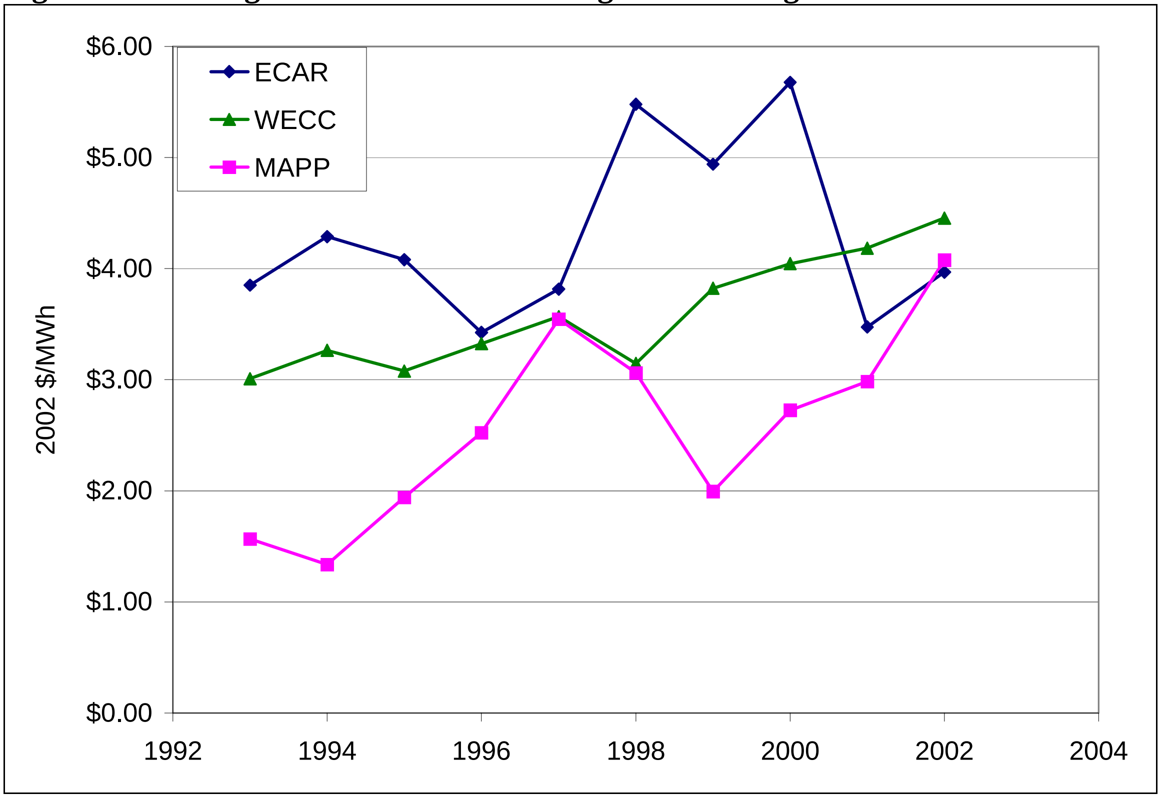
Table 4-2 Gross Revenue from Wheeling in Three Regions (millions of 2002 dollars)

Year	ECAR	MAPP	WECC	United States
1993	$109.29	$22.14	$224.50	$1,362.01
1994	$112.27	$21.99	$212.91	$1,365.09
1995	$121.15	$30.03	$198.17	$1,373.15
1996	$189.08	$38.31	$231.88	$1,541.67
1997	$235.31	$61.04	$240.63	$1,821.70
1998	$370.58	$57.21	$232.01	$2,181.30
1999	$335.68	$44.20	$294.18	$2,417.00
2000	$484.71	$51.17	$352.33	$2,828.12
2001	$546.53	$56.15	$469.15	$3,400.21
2002	$632.31	$56.13	$470.24	$3,968.41

Sources: EIA staff assembled this table from RDI's PowerDat compilation of the EIA 412, FERC 1 and RUS 7 and 12 data.

Figure 4-1 shows the average revenue from wheeling for these regions. Average revenue varies from a low of just over one dollar in 1994 for MAPP to just under six dollars in 1998 and 2000 for ECAR. Over time the range in price difference between the three regions has varied between roughly $0.50/MWh and $4.50/MWh.

Figure 4-1. Average Revenue from Wheeling in Three Regions



Source: EIA staff assembled this table from RDI's PowerDat compilation of the FERC 1 data.

Revenues from Grid Supplied Ancillary Services: FERC does not now collect information on the prices, volumes or revenues the transmission sector earns from supplying ancillary services. FERC proposes to collect revenues from ancillary service sales. Since the grid is often the major, if not sole, source of ancillary services, is useful to collect price and corresponding volume information. That information can be used to test that grid supplied services are priced at marginal cost. Transmission provider OASIS sites contain some ancillary service prices, but these are incomplete, do not include volumes and are not maintained as a time series, see Chapter 5. The ISOs report some scattered, incomplete information on their websites.

Operations and Maintenance Costs: Official data also utility operating costs. Table 4-3 shows the total O&M costs for utilities located in WECC, MAPP and ECAR.

Table 4-3. Total Transmission O&M Costs by Region (millions of 2002dollars)

Year	ECAR	MAPP	WECC	United States

1993	$414.27	$182.66	$1,003.33	
1994	$423.20	$205.65	$1,021.57	
1995	$412.54	$213.68	$1,016.04	
1996	$420.06	$223.42	$1,044.68	
1997	$400.53	$249.22	$1,091.33	
1998	$442.11	$340.38	$1,264.55	
1999	$448.54	$269.00	$1,293.42	
2000	$540.14	$274.36	$1,166.54	
2001	$691.16	$203.12	$950.95	
2002	$810.76	$220.70	$827.02	

Sources: EIA staff assembled this table from RDI's PowerDat compilation of the EIA 412, FERC 1 and RUS 7 and 12 data.

In 2002 , wheeling revenues were about 75% of O&M costs in ECAR, almost 60% in WECC and about 25% in MAPP.

Book values of Plant and Equipment: FERC maintains voluminous records on book values of plant and equipment and on its depreciation. FERC's concentration on the book value of transmission assets reflects its concern with the recovery of prudent costs, including a reasonable return to capital. These historical costs, and their associated debt, will continue to be important to FERC's determination of capital recovery for wholesale transmission. The difference under restructuring is that the precise boundaries between transmission, generation and distribution matter.

External costs and benefits: The system of uniform accounts underlying the FERC Form 1 does not attempt to identify and value benefits and costs that the responding utilities impose on others. Reliability and congestion are leading examples of these costs and benefits. Congestion internal to the northern ISOs is being valued and paid for by market participants. Chapter 5 explains how congestion is valued and presents recent estimates of congestion costs.

Regional accounts: FERC does not require companies to disaggregate their accounts by RTO or ISO. Nor does FERC collect financial data pertaining to RTOs and ISOs. It is not possible to use official data to construct consolidated accounts either for RTOs or ISOs and the transmission providers within their boundaries. Currently most of the United States operates outside of the RTO/ISO structure. At such time as those organizations come to operate large portions of the grid, consolidated regional accounts may become necessary for evaluating regional transmission costs and investments.

Utility Investment and capital stock: Much has been made of the slow growth in the high voltage grid in comparison to the growth in generation NERC, for example annually publishes its compilation of lines 230kV and above

Table 4-4.

Year	Transmission Lines - AC and DC (230 kV and above) (circuit miles)*	Generation Billion of Kilowatthours**
2002	158,605	3,838
2001	157,314	3,736
2000	156,435	3,802
1999	155,669	3,694
1998	154,679	3,620
1997	153,533	3,492
1996	152,098	3,444
1995	150,111	3,353
1994	150,826	3,248
1993	150,953	3,197
1992	149,020	3,084
1991	148,059	3,074
1990	147,271	3,038

***Source:** **NERC ES&D 2003**
**EIA, Annual Energy Review 2002

Annual "Investment" data show little change in response either to generation or increased wholesale trade (see Table 5-7). The FERC Form 1 and the EIA Form 412 record capital additions for publicly owned utilities, investor owned utilities (IOUs). The RUS 7 and 12 report investment data for cooperatives. Table 4-5 shows additions to transmission plant in service, "investment", for 1988-2002. Some the additions represent purchases of existing facilities (and land) and therefore are not investments in the sense of the National Income Accounts. As noted earlier, publicly owned utilities report to EIA on a fiscal year basis and IOUs report on a calendar year. The annual totals therefore are a mixture of fiscal and calendar year expenditures. Moreover, the boundaries between transmission and distribution vary with reporter.

Table 4-5. Capital Additions 1988-2000 (millions of dollars)

Year	Public	IOUs	Cooperatives	Total $	Total 2002$
1988	$910.48	$2,027.85		$2,938.33	$4,053.31
1989	$1,126.49	$2,179.64		$3,306.13	$4,393.48
1990	$522.33	$2,622.63		$3,144.96	$4,022.00
1991	$811.06	$2,174.25		$2,985.31	$3,684.37
1992	$789.26	$2,498.62	$3.38	$3,291.26	$3,965.35
1993	$683.33	$2,378.64	$121.63	$3,183.60	$3,745.63
1994	$614.52	$2,529.35	$191.84	$3,335.72	$3,844.74
1995	$964.96	$2,430.74	$191.03	$3,586.73	$4,045.69
1996	$1,300.00	$2,312.90	$206.90	$3,819.81	$4,226.86
1997	$851.96	$1,957.70	$149.74	$2,959.40	$3,212.23
1998	$640.78	$2,173.06	$255.16	$3,069.00	$3,290.61
1999	$708.58	$2,308.66	$156.19	$3,173.43	$3,354.35
2000	$929.74	$2,612.89	$192.55	$3,735.18	$3,866.69
2001	$836.67	$4,217.03	$246.27	$5,299.97	$5,359.81
2002	$1,124.13	$3,302.30	$220.33	$4,646.75	$4,646.75

Sources: EIA staff assembled this table from RDI's PowerDat compilation of the EIA 412, FERC 1 and RUS 12 data. Nominal dollars were converted to year 2001 dollars using the …..deflator.

Independent Power Producers, Merchant Transmission and RTO/ISO investments: Independent power producers do not report their connection costs. To some extent the costs they incur for grid reinforcement may be reported on the FERC 1. Whether they are or not, they are not identifiable. Merchant Transmission companies do not report capital investment to either FERC or EIA. RTO/ISOs are considered utilities by FERC and are required to report.

4. Filling the Information Gaps

FERC's Commissioners are concerned with the economics of transmission as a standalone enterprise because of their obligation to ensure just and reasonable prices in a restructuring environment. But FERC's financial accounts are more appropriate to the circumstances of integrated regulated utilities selling bundled electricity in a pre-restructuring environment. Apart from a few "transmission only" enterprises, transmission revenues are mostly unrecorded in official data. The data describing transmission's operating costs, capital stock, and investment data are not comparable across reporters because the FERC 1 does not impose a common definition separating transmission from distribution.

The FERC 1 says almost nothing about the economics of transmission. Official data do not capture transmission's financial performance in large part because most transmission revenue is not identifiable. If transmission were fully unbundled its revenues would be unambiguous. Absent that, FERC could require line-of- business reporting, a fundamental change tantamount to a new form. Line of business reporting would require utilities to treat their own bundled sales as if they were unbundled and carried out by others. They would "earn" revenues on transmission to their own customers presumably at the same rates as they charge others under the FERC tariff. Such transfer prices would then be proxies for what transmission would earn if it were in fact a standalone enterprise. How useful or valid these estimates would be is a serious question.

Far less dramatic changes to the FERC 1 would make the data more useful for cost and investment (but not financial) analysis. Sharp definitions of transmission would be a logical place to start. Moreover, additions to transmission plant and equipment reflect purchases of existing assets from others, land and other expenditures that, while relevant for some purposes, are not "investment" in the sense of the National Income Accounts. The EIA forms that are modeled after the FERC 1 share those attributes.

Disaggregating line investment by voltage and identifying investment in grid metering and control would also be helpful. EIA would have to adopt FERC 1 conventions, including FERC's calendar year convention, to permit national totals. In addition, FERC and EIA could require that the accounts be segregated by region (ISO/RTO or NERC region) as appropriate.

Table 4- 6 contains more specific suggestions for the FERC 1 and EIA 411 short of line of business reporting.

Table 4-6. Modify Existing Data Collections.

Information Need	Form	Changes	Comment
1. Consistent separation of transmission from distribution accounts	FERC 1, EIA 412	Explicitly define transmission the same way for all utilities and use that definition in assigning costs, revenues and net capital.	Current data is an "apples and oranges" mix.
2.Ancillary service revenues	FERC 1, EIA 412	Require reporting as proposed by FERC	
3. Re-Dispatch Costs	FERC 1, EIA 412	Require reporting.	Only applicable to utilities owning generators. Not necessary for ISOs
4. Utility investment in the high voltage grid	FERC 1, EIA 412	1. Adopt NIA definition of investment. 2. Report line and associated equipment investment by	Current "additions to plant and equipment" data has very limited use for economic and reliability analysis, though it is

		voltage level. 3. Report investment in metering, communication, software and control of the high voltage grid	important to capital cost recovery.
5. IPP investment	EIA 860	Collect direct connection and grid reinforcement costs from IPPs on the EIA 860	Some of these investments may not be picked up on the FERC 1. See Chapter 5
6. Merchant transmission Investment	EIA 412	Add to the list of respondents and require them to report transmission investments, as defined above, and to fill out Schedules 10 and 11.	Merchant investment and line data is not currently collected.
7. Consistent aggregation	EIA 412	Adopt FERC definitions, see above, and require reporting by calendar year	EIA currently allows reporting by fiscal year.
8. Regional costs	FERC 1, EIA 412	Require reporters to disaggregate cost, revenue, net capital stock and investment by appropriate region	This would allow regional cost comparisons.