SUBMISSION OF
INDIANA INDUSTRIAL ENERGY CONSUMERS, INC.
to the
INDIANA OFFICE OF ENERGY DEVELOPMENT

RECOMMENDATIONS FOR STATE ENERGY POLICY

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EXHIBITS

Indiana Industrial Energy Consumers, Inc. ("INDIEC") makes this submission to the Indiana Office of Energy Development ("OED") in connection with the stakeholder process to develop a State Energy Plan. Because INDIEC represents the interests of industrial facilities as large volume energy consumers, this submission will focus on policy issues of particular concern to industrial consumers relating to the provision of energy services in Indiana.

I. EXECUTIVE SUMMARY

Indiana's past success in establishing a strong manufacturing and industrial base is attributable in significant part to its traditional status as a low-cost energy state, but that advantage has been seriously eroded in recent years. Where Indiana had the fifth lowest industrial energy rates in the nation a decade ago, its ranking has now dropped to 27th. Efficient, reliable and economical energy is essential to Indiana's industrial base. Industrial operations are energy-intensive, consuming nearly half the energy in Indiana and paying some \$3 billion annually for energy services. Industrial businesses operate in highly competitive global markets, so that energy as a major cost component plays a significant role in competitiveness, productivity and economic vitality. Consequently, the availability of reasonably priced energy is a key factor in the ability of Indiana to attract and sustain industrial employers and is a material driver in economic development in the State.

In order to reverse the trend of escalating energy rates and restore Indiana's advantage as a location of choice for industrial operations, the State Energy Policy should include several important elements:

Better options to manage energy costs. The energy industry has been transformed with federal restructuring of wholesale markets, independent operation of the transmission grid on a regional basis, the introduction of retail competition in some states, and cost pressures arising from environmental compliance mandates impacting coal-fired power plants. Despite those changes, Indiana has adhered to the regulated monopoly model for electric service, while providing utilities with one-sided flexibility and increasing opportunities to recover targeted costs through rates. Sophisticated industrial consumers, too, should be provided an effective mechanism to better manage escalating energy costs and to implement creative energy solutions, with appropriate oversight by the Indiana Utility Regulatory Commission ("Commission"). In addition, Indiana should conduct a study through the State Utility Forecasting Group ("SUFG") analyzing alternative regulatory models based on experience in other states, in order to assist in assessing potential areas of improvement and associated benefits for Indiana.

Stronger support for private generation. In a number of contexts, established public policy encourages the development of private electric resources by non-utilities, such as cogeneration plants supporting industrial operations, waste-to-energy facilities, and renewables including wind farms and solar facilities. Among the benefits are diversity of in-state supply resources, reduced need for utility power plant construction at public expense, enhanced capability for industrials to manage and control their own energy needs, and cleaner and more efficient power production. Despite that policy, regulatory obstacles inhibit private generation. In particular, the availability of reasonable back-up and maintenance power from public utilities, access to the transmission grid, and potential challenges from utilities asserting monopoly service rights all act as obstacles to private generation projects. Stronger support in Indiana would promote joint venture projects, third party development of on-site facilities, off-site generation, direct purchases from renewables providers, and other projects utilizing private enterprise to expand energy resources in the State.

Regulatory reform to mitigate the impact of rate trackers. Under traditional regulation, rates are established through rate cases in which the utility's services and financial conditions are reviewed comprehensively. In Indiana, rates have been impacted more and more by tracking mechanisms, which provide automatic increases to account for particular categories of expense. As a result, the rates of Indiana utilities have been increasingly based on pre-approved estimates and accelerated cost recovery, with longer periods between rate cases and less scrutiny of overall rate levels. Improved regulatory standards and procedures would mitigate the impact of trackers by adjusting rate of return to reflect reduced risk, setting caps, and requiring more frequent rate cases. Financial incentives under existing regulation, furthermore, encourage utilities to favor construction projects that add to their rate base over potentially more cost-effective options. Hence, stricter standards for competitive procurement are needed to ensure the selection of least cost alternatives. Finally, a basic principle of ratemaking requires rates to be based on reasonable and fairly allocated costs, but that standard has been eroded by utility inefficiencies, inter-class subsidies and lengthy periods between rate cases. State policy should call for adherence to cost-based rates.

Task Force on Energy for Economic Development. Energy costs are a key factor for industrial operations in Indiana, and directly impact the ability of the State to attract and retain large employers such as the members of INDIEC. The establishment of a Task Force on Energy for Economic Development, comprised of representatives of the Indiana Economic Development Corporation ("IEDC"), OED, INDIEC, the Indiana Energy Association ("IEA") and any other stakeholders deemed appropriate to the mission, would provide the Administration with ongoing input and support as the State Energy Policy is implemented.

Continued commitment to energy efficiency. INDIEC strongly supports energy efficiency. The opt-out approach for industrials under current law is sound policy because industrials can and do implement energy efficiency measures independent of regulatory programs and consistent with their own economic cost-benefit analyses, as energy costs directly affect their ability to compete effectively. Industrials further advance energy efficiency goals by participating in demand response and interruptible service tariffs. An impediment to energy efficiency under current law, however, is the imposition of a lost margin tracker, by which the utility recovers lost profits attributable to reduced energy usage. Lost margin recovery is inconsistent with fundamental ratemaking principles and fosters misguided incentives, because consumers are denied the full cost savings from reduced consumption.

II. CHALLENGES FOR INDUSTRIAL ENERGY COSTS IN INDIANA

Historically, Indiana has been able to build and sustain a strong industrial base in large part due to low-cost energy. That advantage, however, has been lost with rapidly rising electricity rates. The State Energy Policy, accordingly, must recognize the adverse change in status and take affirmative steps to address the challenges of escalating energy costs.

A. About INDIEC

INDIEC represents large volume consumers with respect to energy issues in Indiana. Since the mid-1980s, INDIEC has advocated for sound energy policy to ensure the reliable and cost-effective provision of energy to industrial operations in Indiana. INDIEC seeks to establish and preserve an energy supply and cost environment in Indiana that attracts new business and enables existing businesses to thrive and expand.

INDIEC has thirty-two members, which predominantly operate large industrial facilities in Indiana consuming large volumes of energy. A list of INDIEC members is attached as Exhibit A. INDIEC has several affiliate members that include a trade association, competitive energy businesses and education service centers. Unlike some organizations that represent both industrial businesses and energy utilities, the membership of INDIEC does not include any public utilities. INDIEC members collectively employ about 55,000 Hoosiers and consume around one third of the total energy in Indiana.

B. Importance of Reasonable Energy Costs to Industrials in Indiana

Industrial operations are a critical element of the Indiana economy. Manufacturing accounts for more than 25% of Indiana's gross domestic product,[1] the highest percentage of any

[1] *See* Stats Indiana, *Economy: Gross Domestic Product by State* (based on U.S. Bureau of Economic Analysis data), available at http://www.stats.indiana.edu/sip/.

state in the country.[2] Nearly half a million Hoosiers are employed by manufacturers, accounting for about one in six jobs in the State,[3] also the highest percentage in the nation.[4]

At the same time, industrial operations are highly energy-intensive. Industrials consume nearly half the electricity in Indiana.[5] The cost of that vital resource is a major component in the cost of production. Industrials in Indiana pay more than $3 billion annually for electricity.[6] Those businesses operate, furthermore, in intensely competitive national and global markets. Because energy is such a substantial cost element, the availability of efficient, reliable and reasonably priced electricity is a key driver in decisions by industrials regarding where to locate new facilities, where to source production, and where to expand or constrict existing facilities. The cost of electricity, consequently, has a significant impact on the vitality of industrial operations and on economic development in Indiana.

C. Indiana Has Lost Its Status as a Low-Cost Energy State

Historically, Indiana has enjoyed an advantage in attracting and retaining industrial employers by virtue of its low-cost energy. Ten years ago, Indiana ranked fifth lowest in the United States in average electricity prices for industrial consumers. See Exhibit B, attached hereto. That former advantage, however, has been lost in recent years. As of 2013, Indiana had dropped to a ranking of 27th in the United States in industrial electricity prices. That unfavorable trend is continuing in the wrong direction and is an increasing impediment to economic growth in Indiana.

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[2] *See Indiana Leads the U.S. in Manufacturing Production, Employment*, available at http://imaweb.com/indiana-leads-u-s-manufacturing-production-employment/.
[3] *See* Stats Indiana, *Workforce: Industry Employment and Wages* (based on U.S. Bureau of Economic Analysis data), available at http://www.stats.indiana.edu/sip/.
[4] *See Indiana Leads the U.S. in Manufacturing Production, Employment*, available at http://imaweb.com/indiana-leads-u-s-manufacturing-production-employment/.
[5] *See* U.S. Energy Information Administration, *Electric Power Monthly* (with data for December 2013) (February 2014), Table 5.4.B, available at http://www.eia.gov/electricity/monthly/.
[6] *See* U.S. Energy Information Administration, *Electric Power Monthly* (with data for December 2013) (February 2014), Table 5.5.B, available at http://www.eia.gov/electricity/monthly/.

Attached as Exhibit C is a chart showing average industrial electricity prices in Indiana as compared to the United States as a whole since 1997.[7] Where Indiana traditionally offered electricity rates substantially below the national average, in recent years the gap has narrowed. Where average industrial prices across the United States have been stable the past five years, Indiana prices have increased steeply and Indiana's cost advantage has disappeared.

The same unfavorable trend is apparent on a regional basis. Exhibit D shows the dramatic rise in Indiana energy rates for industrials as compared to the four bordering states, Illinois, Ohio, Michigan and Kentucky. Unlike Indiana, Kentucky has maintained its cost position over the past five years. During the same period, industrial prices in Illinois and Ohio have been dropping while Indiana's rates have continued to rise precipitously. Where Indiana long enjoyed a decided cost advantage for industrial electricity compared to its neighbors to the east and west, Illinois and Ohio now offer industrials lower electricity prices than Indiana.

Indiana is not alone in facing the challenge of upward cost pressure on industrial electricity rates. Exhibit E compares Indiana's industrial rates to those of other upper Midwestern states: Wisconsin, Minnesota and Iowa. Like Indiana, several other Midwestern states are facing a serious problem with rising electricity costs, making them less attractive as potential locations for new industrial facilities and plant expansions.

Several factors are driving up industrial electricity rates in Indiana, and will continue to impose upward cost pressure in the future. Indiana is highly dependent on electricity generated by coal-fired power plants, which are subject to expensive environmental compliance mandates. As of 2012, over three fourths of the electricity generated in Indiana was coming from coal

[7] Data for Exhibits C, D, and E taken from U.S. Energy Information Administration. Data for 1997-2012 taken from *1990-2012 Average Price by State by Provider*, available at http://www.eia.gov/electricity/data/state/. Data for 2013 taken from *Electric Power Monthly* (with data for December 2013) (February 2014), Table 5.6.B, available at http://www.eia.gov/electricity/monthly/.

plants.[8] Many of those facilities, furthermore, are nearing the end of their useful lives and are becoming candidates for plant retirement.[9] Combined with the massive cost of environmental compliance, the Commission is predicting an unprecedented wave of substantial capital investments to retrofit or retire and replace aging coal-fired generation units, which will continue to drive up electricity prices for years to come.[10] In a 2013 report, the SUFG projected a 30% increase in Indiana electricity rates over the next decade, assuming no additional environmental regulations and utilities take measures to extend the life of coal plants for as long as possible.[11] With any new environmental mandates or added power plant retirements, the projected increase in the future will be even higher.

Another factor adversely impacting the cost of electricity in Indiana has been a regulatory structure oriented on supporting utility financial performance. In particular, legislation in recent years has provided utilities with opportunities to secure automatic rate increases through rate trackers designed to recover the costs of defined categories of expenses, in many instances through a pre-approval process based on cost estimates and projections. The cumulative effect of trackers and the erosion of rate protections is addressed in more detail infra Section V, below.

[8] *See* Indiana Utility Regulatory Commission, *2013 Annual Report to the Regulatory Flexibility Committee of the Indiana General Assembly*, at 32 & Chart 1 (based on 2012 projections), at http://www.in.gov/iurc/2493.htm.
[9] *Id.* at 26-28.
[10] *Id.* at 26.
[11] *See* State Utility Forecasting Group, *Indiana Electricity Projections: The 2013 Forecast* (December 2013) at 3-6.

III. BETTER OPTIONS FOR INDUSTRIALS TO MANAGE ENERGY COSTS

In light of significant changes in the energy market and the problems posed by rising industrial energy prices in Indiana, two steps are appropriate to provide industrial employers in Indiana with more effective options to manage energy costs. First, a process should be established by which large volume consumers can gain regulatory approval for flexible and innovative energy arrangements, similar to an existing procedure that is currently available only to energy utilities seeking to implement alternative regulatory plans. Second, the SUFG should conduct an analysis of alternative regulatory models in place in other states, to provide baseline data to evaluate best practices nationally and to assess potential improvements for Indiana.

A. The Energy Market Has Undergone Significant Transformation

Over the past two decades, regulation of the electric industry has been substantially restructured. Under traditional regulation, the Federal Energy Regulatory Commission ("FERC") regulates the interstate transmission grid and the wholesale market in which power is sold to utilities and other resellers. States, through entities like the Commission, regulate the local distribution systems of public utilities and retail sales to end use consumers. Following the prior pattern of federal deregulation in markets such as airline transportation, trucking, telecommunications and natural gas, FERC initiated a policy of restructuring the electric industry in the 1990s. That policy led to the formation of independent transmission system operators like the Midcontinent Independent System Operator ("MISO"), which manage transmission assets and power markets on a regional interstate basis. The federal restructuring also promoted competition in the wholesale market, in place of rate regulation.

In the context of the federal restructuring, states across the country, including Indiana, considered changes to traditional utility regulation. Sixteen jurisdictions, primarily high-cost states in the northeast, now have active retail competition programs by which some or all consumers are able to select among alternative power providers.[12] In those states, the generation and sale of electric power has been deregulated, but the transmission and distribution functions continue to be provided by public utilities at regulated rates. Electric competition bills were introduced in Indiana over several sessions in the late 1990s, but did not advance in light of the low rates prevalent in Indiana at the time. In 2000, an energy crisis in California exposed structural flaws in the restructuring model implemented in that state, effectively halting the national trend toward restructuring retail electric markets.

Indiana, accordingly, has retained the regulated monopoly model for retail sales of electricity by vertically integrated energy utilities. In significant respects, however, the regulatory structure in Indiana has been revised to establish alternatives and relaxed standards for the unilateral benefit of utilities. In particular, in 1995 the General Assembly enacted the Alternative Utility Regulation Act ("AUR Act") to provide utilities with flexibility in light of the increasingly competitive energy market. See Ind. Code ch. 8-1-2.5. Under the AUR Act, an energy utility can seek Commission approval of a deregulatory initiative or an alternative regulatory plan, outside the restrictions and standards of traditional regulation.[13] The AUR Act is available only to energy utilities, only an energy utility can file a petition under the Act, and only an energy utility can present an alternative regulatory plan.[14] If the Commission materially modifies a utility proposal under the Act, the utility can exercise a veto and withdraw the plan.[15]

Through other legislation, utilities in Indiana also have been granted greater flexibility in seeking rate increases. Under traditional regulation, Indiana once followed the "used and useful"

[12] *See* U.S. Energy Information Administration, "Status of Electricity Restructuring by State" map, available at http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html.
[13] *See* Ind. Code §§8-1-2.5-5, 8-1-2.5-6.
[14] *See* Ind. Code §§8-1-2.5-4, 8-1-2.5-5(a), 8-1-2.5-6(a).
[15] *See* Ind. Code §§8-1-2.5-6(e), (f).

principle by which a utility must complete construction of facilities and put them in operation actually providing service to the public before seeking cost recovery through regulated rates.[16] Rates were set by the Commission through rate cases, in which the utility's services and financial performance were comprehensively reviewed in order to determine overall rate levels that would cover prudent costs and provide a reasonable return to utility investors.[17] In recent decades, however, legislation has provided Indiana utilities with greater opportunities to recover costs through rate trackers, imposed outside the context of rate cases to provide automatic rate adjustments for specific categories of costs. In some instances, trackers are implemented based on pre-approval of proposed projects at estimated costs, allowing rate recovery before a given asset is placed in service. With an increasing portion of utility rates consisting of trackers, general rate cases have become more infrequent and scrutiny of overall rates much less exacting.

B. <u>Large Consumers Need a Process to Implement Energy Alternatives</u>

On the one hand, energy utilities in Indiana may now take advantage of the deregulated wholesale market, regional operation of transmission systems, flexible state regulation opportunities, and the availability of an array of rate trackers. On the other hand, large volume consumers such as the members of INDIEC remain subject to the regulated rates of monopoly energy suppliers. Regulated utilities have financial incentive to protect their monopoly franchises and exclusive sales territories, and to resist efforts by large customers seeking more economical alternatives. Under current Indiana law, industrials have limited options to manage rapidly rising energy costs, to implement efficient arrangements and to fashion creative energy solutions.

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[16] *Citizens Action Coalition v. N. Ind. Pub. Serv. Co.*, 485 N.E.2d 610, 614 (Ind. 1985), *cert. denied,* 476 U.S. 1137 (1986).
[17] *City of Evansville v. S. Ind. Gas and Electric Co.*, 167 Ind. App. 472, 479, 339 N.E.2d 562, 569 (1975); *L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 657, 351 N.E.2d 814, 818 (1976).

A variety of potentially beneficial industrial energy arrangements face regulatory obstacles under the existing utility structure in Indiana:

- As explained in more detail infra Section IV, private generation projects can provide industrials with efficient alternatives to energy purchases from utilities, enhancing Indiana's portfolio of supply resources. Such projects, however, can be hindered by the unavailability of back-up and maintenance power on reasonable terms, by lack of access to the transmission grid, and by the threat of litigation by utilities asserting monopoly service rights.
- Negotiated rates are available to a limited extent to support economic development, but only for short periods with typically modest discounts that diminish over time and generally only with utility consent. The current framework is poorly suited to support long-term industrial investments that often ratchet up production while the rate benefits are disappearing.
- Integrated business operations with centralized purchasing are generally unable, under existing regulation, to take advantage of aggregated metering and the economies of scale arising from joint purchases on behalf of multiple locations.
- An industrial may wish to purchase directly from a wind farm or solar facility, or pursue another competitive supply option, but such purchased power alternatives may be blocked by the monopoly utility under current Indiana law.

INDIEC therefore proposes the establishment of a regulatory mechanism by which large volume consumers can seek Commission approval of alternative energy arrangements. Such a process would balance the flexibility currently available only to energy utilities with a corresponding flexibility supporting large employers in Indiana. Whether the process is effectuated by an amendment to the existing AUR Act or through a standalone statutory provision, the important components of a fair procedure would include the presentation of a consumer proposal in a formal regulatory proceeding, an opportunity for all interested parties, including the utility, to participate and submit evidence, and a requirement that the Commission grant approval under a public interest and reasonableness standard. With those procedural protections, only reasonable proposals that advance efficiency, economic development and productivity, without impairing the public interest, will be subject to approval.

Even where an approved alternative arrangement results in reduced sales by a utility to a particular industrial consumer, or involves reduced profit margin on continued utility sales, proposals for flexible regulation need not add to the rate burden of other consumers or result in the shifting of costs to other ratepayers. Any reductions in the demand for utility services would offset load growth and hence mitigate or delay the need for building new power plants or other expensive utility construction projects, with consequent rate increases. There would be no impact on the rates of other consumers, furthermore, without the filing of a rate case by the utility, which would occur only if a threshold of materiality were reached. Utilities generally, after all, are expected to manage fluctuations in demand and are compensated for risk through their regulated rate of return.[18] For example, a series of private generators were installed at industrial locations in northern Indiana in the 1990s, but Northern Indiana Public Service Company ("NIPSCO") did not file its next electric rate case until 2008. If and when a rate case is filed, the Commission would consider a broad array of potentially countervailing factors.

[18] *L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 683-84, 351 N.E.2d 814, 834-35 (1976) (explaining that unnecessary plant capacity is not used and useful and cannot be included in rates, and that bad business judgments as to the plant capacity that will be necessary in the future is a risk to the utility, not the public).

At all points, Commission oversight of the process will ensure that alternative energy arrangements do not impair the interests of the public in general. The Commission has all necessary authority to address any issues of stranded costs or allegations of rate inequities.

C. The SUFG Should Conduct a Study of Alternative Regulatory Models

The energy industry has undergone substantial transformation in the past two decades, but the regulatory model by which retail service is provided to consumers by monopoly utilities has been in place in Indiana for an entire century. The changes implemented by the General Assembly have been in the direction of providing regulated utilities in Indiana with greater flexibility and opportunities to secure accelerated rate recovery of targeted costs based on pre-approvals and estimates. Even the largest and most sophisticated consumers, however, remain subject to the provision of electric service by monopoly suppliers at regulated rates.

At the same time, other states have implemented alternative approaches to energy regulation, including restructuring to promote retail competition and customer choice. In those restructured states, consumers may choose among competing electricity suppliers, but the transmission and distribution functions are still performed by public utilities at regulated rates. A variety of structures have been applied in restructured states. For example, Illinois imposed a rate freeze and experienced price volatility when the freeze was lifted. Michigan set a load cap of ten percent as a limit on customers eligible to select alternative suppliers, but has recently explored changes to that restriction as well as additional strategies to manage rising electricity costs. Some states have mandated divestiture of generation assets by utilities. There have been various approaches to promoting the construction of new generation, including reliance on market dynamics and other mechanisms.

States that have retained the regulated monopoly structure, moreover, have implemented measures to mitigate cost pressures with varying success. For example, Kentucky, like Indiana, relies heavily on coal-fired generation, but has retained its cost advantage over time.[19] As Indiana has dropped from having the 5th lowest industrial energy rates in the nation to a ranking of 27th, both traditionally regulated and restructured states have maintained or improved their positions.

Since Indiana last considered retail competition legislation in the late 1990s, a wealth of data has been accumulated on the relative performance of a wide variety of energy market strategies employed by different jurisdictions. Attached as Exhibit F is a chart showing changes in weighted average industrial electricity prices in restructured and traditionally regulated states.[20] A number of factors affect electricity prices in addition to regulatory model, and many policy considerations must be weighed in determining the optimal approach for Indiana. The complicated process of reforming energy regulation calls for careful deliberation and analysis, and to that end a study of the relative performance and merits of energy policies implemented in other states would provide a valuable baseline of experience.

The purpose of the proposed study would be to analyze alternative regulatory models in other states and assess performance in delivering reliable, efficient and economical service. For jurisdictions that have introduced customer choice, factors to address would include the effect on prices, the degree of price volatility and any stabilizing mechanisms, handling of stranded costs, if any, and the adequacy of provisions to ensure reliability and development of supply resources.

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[19] *See* Exhibit D.

[20] Data for Exhibit F taken U.S. Energy Information Administration. For 1997-2012 data, see *1990-2012 Retail Sales of Electricity by State by Sector by Provider* and *1990-2012 Revenue from Retail Sales of Electricity by State By Sector by Provider*, available at http://www.eia.gov/electricity/data/state/. For 2013 data, see *Electric Power Monthly* (with data for December 2013) (February 2014), Table 5.4B and Table 5.5B, available at http://www.eia.gov/electricity/monthly/.

For traditionally regulated states, issues to examine would include the extent of rate trackers, authorized rate of return levels, strategies for environmental compliance, and effectiveness of any energy efficiency programs. The analysis of experience in other states should be useful in determining the approach best suited to promoting efficiency, reliability, diversity of supply options, the restoration of Indiana's energy advantage and competitiveness with neighboring states, and the equitable allocation of risks and benefits for all Indiana consumers.

The SUFG was established in 1985 to provide independent analysis in forecasting energy needs and to assist in resource planning. It operates at the Purdue University Energy Center under contract with the Commission. In addition to periodic energy forecasts, the SUFG performs special studies on request to inform state government on matters of energy policy. Given its independence and expertise in analyzing energy data, the SUFG is the appropriate entity to conduct a study analyzing alternative regulatory models implemented in other jurisdictions, including both restructured and regulated states. The results of that study will provide valuable insight on best practices and successful strategies adopted in other states, and hence will provide useful guidance on the optimal approach to energy regulation in Indiana.

IV. STRONGER SUPPORT FOR PRIVATE GENERATION PROJECTS

As the cost of electricity moves higher, the economics of self-supply options for large consumers become more attractive. Private generation projects, furthermore, reduce the burden of utility construction at public expense and promote the diversity of in-state supply resources. The existing regulatory structure, however, inhibits the development of efficient and economical generation projects by non-utilities. Therefore, the State Energy Policy should include measures to support and encourage the construction and deployment of private generation projects.

A. Sound Policy Favors Private Energy Resources

In a number of contexts, established public policy favors the construction of private generation facilities by non-utilities. In particular, privately owned cogeneration facilities and combined heat and power units are typically used by an industrial complex to provide both electricity and useful thermal output, such as steam, to support the host's energy needs. Such private energy resources are efficient, environmentally friendly and encouraged by both Indiana and federal law.[21] Small power production[22] and waste-to-energy facilities[23] are additional private generation options for industrials that are favored by both Indiana and federal law. In addition, state and federal law encourage the development of renewable sources of energy such as wind farms and solar facilities,[24] which are often constructed and operated by non-utility developers.

Support for private generation is sound energy policy. As public utilities in Indiana are facing a wave of retirements for aging coal-fired generation units, which are under increasing cost pressure for environmental compliance, private generation mitigates and delays the need for

[21] *See* Ind. Code §8-1-2.4-1 *et seq.*; Ind. Code §8-1-37-4(a)(20); 16 U.S.C. §824a-3.
[22] *See* Ind. Code §8-1-2.4-5(a); 16 U.S.C. §796(17)(A)(ii).
[23] *See* Ind. Code §8-1-37-4(a)(5)(D), (9); 16 U.S.C. §796(17)(A)(i).
[24] *See* Ind. Code §8-1-2.4-2(b)(1); Ind. Code §8-1-37-4(a)(1)-(6), (11); 16 U.S.C. §796(17)(A)(i).

utilities to build expensive power plants and recover those costs through regulated rates. To the extent private investment supports a portion of future energy demand, the volume of expense borne by public resources is reduced. Private generation projects, moreover, enhance the variety and diversity of in-state supply resources. They also provide a means for industrials to control and manage their own energy needs. In addition, such facilities are typically both energy-efficient and environmentally friendly, promoting efficiency and low-emission resources.

B. Current Regulation Inhibits Private Energy Development

Under existing regulation in Indiana, public utilities have incentive and opportunity to discourage the development of private generation projects. A consumer pursuing a self-supply option seeks to reduce dependence on purchases from the monopoly utility. The utility in that instance will generally prefer continued or increased energy sales with the associated stream of rate revenues. Regulated rates provide utilities with a return of and a return on investment in physical plant and equipment, and consequently utilities have a profit stake in their own construction projects, particularly where accelerated rate recovery and reduced risk are available through tracker mechanisms. A shift in a portion of the construction burden to private enterprise, therefore, reducing the scope of utility projects funded by the public through regulated rates, creates assets on which the utility does not derive a financial return.

While the policy favoring private generation is firmly established[25] and the right of individual consumers to supply their own energy needs is settled law in Indiana,[26] the regulatory framework nevertheless presents obstacles hindering private energy projects. When private generation supports an industrial operation, the industrial process from time to time requires a

[25] *See* Ind. Code §8-1-2.4-1 *et seq.*; Ind. Code §8-1-37-4(a); 16 U.S.C. §§796(17)(A), 824a-3.

[26] *See United States Steel Corp. v. N. Ind.Pub. Serv. Co.*, 951 N.E.2d 542, 551-57 (Ind. Ct. App. 2011), *tr. den.*, 963 N.E.2d 1119 (Ind. 2012); *BP Products v. Office of Util. Consumer Counselor*, 947 N.E.2d 471, (Ind. Ct. App.), *mod'd on reh. on diff. grounds*, 964 N.E.2d 234 (2011), *tr. dismissed*, 963 N.E.2d 1120 (Ind. 2012); *United States Steel Corp. v. N. Ind. Pub. Serv. Co.*, 486 N.E.2d 1082, 1084-85 (Ind. Ct. App. 1985).

supply of back-up, maintenance or supplemental power from the public utility on occasions where the private facility has an outage, is down for service or otherwise is unable to meet the consumer's full requirements. Utilities are required by law to provide such services on reasonable, cost-based terms, but in practice the rates and terms of service vary from utility to utility and in many instances reflect cost assumptions that predate the deregulated wholesale market. The industrial consumer's need for back-up, maintenance and supplemental power can present the utility with bargaining leverage and opportunity to make the private generation project less attractive.

Similarly, operators of private generation facilities may seek access to the utility's transmission and distribution system and face difficulties in securing reasonable terms. A utility is required by law, for example, to purchase excess power that is produced by a cogeneration unit but not needed to meet the needs of the host industrial facility, but the utility favoring its own generation may resist paying reasonable compensation for purchased power that would then be available to serve other utility customers. Access to the grid may be the most efficient way to transmit power from a private generating unit to the point of consumption, but that requires an acceptable arrangement with the utility and reasonable terms of service. Whenever the operator of a private generation facility seeks to interconnect with the utility grid, the utility has opportunity to propose burdensome or unreasonable terms and conditions.

The monopoly service territories of electric utilities in Indiana have a statutory basis codified in the Service Area Assignment Act. See Ind. Code ch. 8-1-2.3. Under that Act, a utility is granted the exclusive right to render retail service to all consumers within its assigned territory,[27] and may enforce that right through civil litigation providing for an award of damages,

[27] *See* Ind. Code §8-1-2.3-4(a).

injunctive relief and attorney fees in the event of a violation.[28] Although the Service Area Assignments Act was designed to address boundary disputes between public utilities and rural cooperatives,[29] the exclusive service rights and litigation remedies under that statute raise a cloud of potential challenge to private energy arrangements. The threat of potential litigation by a utility claiming infringement of its exclusive service franchise can be an effective deterrent to otherwise efficient and beneficial projects involving, for example, joint ventures, third party developers or off-site facilities.

C. <u>The State Energy Policy Should Support Private Generation</u>

In the 2014 session, the General Assembly reiterated the policy favoring private generation by lifting an 80 megawatt cap on cogeneration facilities eligible for back-up, maintenance and supplemental power service and for sales of excess energy.[30] Indiana law thus supports industrial consumers utilizing private energy facilities on their property, but remaining regulatory impediments still need to be addressed. In particular, the Commission should be directed to establish reasonable and non-discriminatory rates and terms of service for back-up, maintenance and supplemental power and for sales of excess energy to utilities. In addition, the Service Area Assignments Act should be amended to clarify that private generation facilities do not violate an electric utility's exclusive service rights.

With respect to projects where the application of regulatory restrictions is less settled and the threat of litigation is a greater risk factor, the establishment of clear state policy and clarifying legislation would promote the development of private generation:

- Joint venture projects involving multiple consumers, partnerships with utilities or utility affiliates, or arrangements with facility developers or equipment suppliers

[28] *See* Ind. Code §8-1-2.3-4(b).
[29] *See United REMC v. Ind. & Mich. Electric Co.*, 549 N.E.2d 1019, 1021 (Ind. 1990).
[30] *See* HEA 1423.

may be attractive for financing purposes or efficient scope, but the involvement of more than one individual consumer raises the risk of regulatory challenge.

- An industrial operation may prefer not to undertake construction projects and manage generation assets that are ancillary to its primary business, and could beneficially work with a third party developer to install and operate a private generation unit. The presence of an independent developer, however, increases the likelihood of utility resistance.
- The optimal location for private generation facilities may be outside the industrial complex, and delivery over the utility transmission and distribution system may be the most efficient approach, but the need for utility cooperation makes such projects more difficult to implement.
- Wind farms and solar power developers cannot sell directly to consumers under present regulation, and instead must sell power to the local utility which in turn has the exclusive right to sell to consumers. An industrial seeking direct access to a conveniently located provider of renewable energy should be able to enter into an advantageous arrangement without utilizing the utility as a middleman.

In those and similar situations, Indiana policy should support industrials seeking to develop private generation projects.

Aside from the impediments arising from the regulatory framework, private generation projects also encounter challenges similar to other types of industrial development. The siting and permitting process can be administratively burdensome. The policy favoring private generation is not fully reflected in access to tax incentives and the availability of financing support. The State Energy Policy, accordingly, should recognize that promoting development of efficient and economically sound energy resources makes Indiana more attractive to large employers and consequently should be supported with the same economic development tools utilized to encourage new production facilities and plant expansions.

V. REGULATORY REFORM TO MITIGATE RATE INCREASES

Indiana has departed from traditional regulation in respects that unilaterally favor utilities rather than consumers. That one-sided trend is especially apparent in the array of statutory tracker mechanisms that enable utilities to implement rate increases to recover specified categories of costs more quickly, based on pre-approvals and cost estimates, and thereby avoid business risk and the more comprehensive review of rates that occurs in a general rate proceeding. In order to restore needed regulatory balance, consumer rate protections are required to mitigate the impact of trackers and better ensure reasonable rates. Given the financial incentives that incline utilities to favor self-build options, furthermore, the discipline of cost efficiency should be imposed through stronger competitive procurement standards. In addition, the principle of cost-based rates should be preserved and enforced.

A. Trackers Have Eroded the Protections of Traditional Regulation

Under traditional regulation, utility rates are set through general rate proceedings in which the utility's operations and financial performance are comprehensively reviewed. The Commission evaluates the utility's plant and equipment used to provide service to the public, and that forms the rate base on which utility investors are entitled to earn a return.[31] Only "used and useful" assets that have been placed in service are eligible for inclusion in rate base; during construction the utility carries the cost and bears the risk.[32] By reference to a test year of recent operational results, adjusted for defined circumstances to reflect anticipated future conditions, the Commission sets rate levels that allow the utility, under prudent management, to cover operating expenses and to earn a return of (through a depreciation allowance) and a return on

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[31] *City of Evansville v. S. Ind. Gas and Electric Co.*, 167 Ind. App. 472, 479, 339 N.E.2d 562, 569 (1975); *L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 657, 351 N.E.2d 814, 818 (1976).

[32] *Citizens Action Coalition v. N. Ind. Pub. Serv. Co.*, 485 N.E.2d 610, 614 (Ind. 1985), *cert. denied,* 476 U.S. 1137 (1986); *City of Evansville v. S. Ind. Gas and Electric Co.*, 167 Ind. App. 472, 498, 339 N.E.2d 562, 579 (1975).

(profit margin) its rate base assets.[33] Rates are set under a "just and reasonable" standard that is designed to provide overall revenue levels enabling the utility to furnish reliable and efficient service to the public while providing an opportunity to earn a reasonable return commensurate with other businesses having a similar risk profile.[34] The rate requirements are then allocated among customer classes based on the costs incurred by the utility in serving the particular class.

By virtue of a variety of statutory provisions enacted over time, however, the traditional process for utilities to seek rate increases has been supplemented with trackers that permit periodic rate adjustments to recover a variety of specific categories of costs in isolation, without regard to the sufficiency of overall rates. Trackers available to utilities under Indiana law now include special rate adjustments to recover fuel costs,[35] construction expenses for new power plants,[36] the costs of environmental compliance projects,[37] funds expended pursuant to federal mandates,[38] and planned investments in transmission, distribution and storage facilities.[39] In short, major expense categories and most capital projects are covered by rate trackers. For substantial construction projects, the process can involve pre-approval by the Commission based on a utility proposal and estimated budget, with cost recovery then being phased into rates during the construction process, in contrast to traditional application of the "used and useful" principle.

The result has been a one-way upward trend in rates and excessive periods between general rate cases. With major expenditures eligible for accelerated rate recovery, in isolation of

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[33] *City of Evansville v. S. Ind. Gas and Electric Co.*, 167 Ind. App. 472, 481, 339 N.E.2d 562, 570 (1975); *L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 660, 351 N.E.2d 814, 821 (1976).
[34] *Id. See also* Ind. Code §8-1-2-4; *Ind. Gas Co. v. Office of Util. Consumer Counselor*, 675 N.E.2d 739, 748 (Ind. Ct. App.), *tr. den.*, 690 N.E.2d 1180 (Ind. 1997).
[35] *See* Ind. Code §8-1-2-42(b)-(f).
[36] *See* Ind. Code §8-1-8.5-1 *et seq.*; Ind. Code §8-1-8.7-1 *et seq.*; Ind. Code §8-1-8.8-1 *et seq.*; Ind. Code §8-1-27-1 *et seq.*
[37] *See* Ind. Code §§8-1-2-6.6, 6.7, 6.8; Ind. Code §8-1-8.7-1 *et seq.*; Ind. Code §8-1-8.8-1 *et seq.*; Ind. Code §8-1-27-1 *et seq.*; Ind. Code §8-1-37-1 *et seq.*
[38] *See* Ind. Code §8-1-8.4-1 *et seq.*
[39] *See* Ind. Code §8-1-39-1 *et seq.*

the many other factors bearing on the reasonableness and overall sufficiency of rate levels, the utility has reduced need to file a rate case and subject its performance to comprehensive scrutiny. An increase in one kind of expense may be offset by a decrease in another, or load growth may result in greater sales volume and hence higher profits, but through a tracker a utility can secure a rate increase to reflect a defined cost category in isolation of all other conditions affecting comprehensive financial results. Further analysis explaining the impact of trackers on rates is presented in the attached Exhibit G.

Attached as Exhibit H is a summary showing the dates of rate case filings for Indiana's five investor-owned electric utilities over the past twenty years. Indiana utilities are now going for decades without the thorough review of rate levels that occurs in a general rate proceeding, while securing frequent rate adjustments through trackers.[40] Tracker revenue now constitutes a substantial portion of total electric rates in Indiana. In 2013, Indiana's five investor-owned electric utilities collected revenue in the billions of dollars through trackers.

The legislative trend towards a plethora of trackers increasing rates for targeted costs undermines the ratepayer protections of traditional regulation in other respects. When rates are set based on pre-approvals, forecasts and estimated budgets, the certainty of actual costs and completed projects is lost. Once a utility secures regulatory approval for a proposal and begins collecting costs through rates, the discipline of efficiency is undermined, cost overruns become too easy to justify, and incurred expenses become too difficult to question. That phenomenon is exemplified by the Edwardsport power plant constructed by Duke Energy Indiana, for which

[40] Northern Indiana Public Service Company went from 1986 until 2008 (Commission Cause Nos. 38045, 43526) between electric rate cases; Indianapolis Power & Light Company has not filed a rate case since 1994 (Commission Cause No. 39938); Duke Energy Indiana has not filed a rate case since 2002 (Commission Cause No. 42359); Indiana Michigan Power went from 1991 until 2007 between rate case filings (Commission Cause Nos. 39314, 43306); and Southern Indiana Gas & Electric Company went from 1993 until 2006 between electric rate cases (Commission Cause Nos. 39871, 43111).

massive costs have been recovered through a rate tracker. The project was initially pre-approved at an estimated budget of $1.985 billion, and six months after that approval Duke sought to increase the cost estimate to $2.35 billion, and after a short interval Duke requested another increase to $2.88 billion.[41]

By accelerating rate adjustments and collecting costs for pre-approved projects, the utility greatly augments the certainty of rate recovery and reduces its regulatory risk. Indiana utilities, however, have continued to enjoy regulated returns at levels that do not reflect the reduced risks arising from the shift in legislative policy towards more and more trackers. Exhibit I shows the approved return on equity authorized in the rate orders for Indiana electric utilities since 1990, indicating only a slight dip in the past two decades despite the increasing prevalence of trackers in Indiana. The same exhibit compares the current authorized rate of return for Indiana's electric utilities with the national average for investor-owned electric utilities in 2013. In each instance, Indiana utilities enjoy higher returns despite the reduction in risk arising from the array of rate trackers in Indiana.

B. Regulatory Reforms Are Needed to Mitigate the Impact of Trackers

The rate benefits available to Indiana utilities through statutory tracker mechanisms should be balanced with protections to ensure that ratepayers are not subjected to unreasonable and excessive rate increases:

- When a tracker is approved for a given utility with a material impact on rates, the utility should be required to commence a general rate case within two years so that the Commission can review the many other factors affecting rates and make appropriate adjustments to ensure reasonable rate levels.

[41] *See In re Duke Energy Indiana*, Cause No. 43114 IGCC 4S1 (IURC 12/27/2012) at pp. 7-8, *aff'd*, *Citizens Action Coalition v. Duke Energy*, 2014 WL 1092210 (Ind. Ct. App. 2014), *reh. pending*. The Commission ultimately approved a settlement establishing a hard cap of $2.595 billion.

- The Commission already has authority to conduct a review of a utility's basic rates and charges every four years,[42] but in practice that authority has not been exercised to require rate cases at that interval. Utilities should be required to commence general rate cases to set basic rates and charges at intervals of no longer than four years.
- When a tracker is approved for a significant expense category, the utility derives enhanced certainty of rate recovery and accelerated collection through rates. The level of risk faced by the utility is thereby reduced. The Commission, therefore, should be authorized to make a downward adjustment to the utility's authorized rate of return to reflect the reduced risk when a tracker is authorized.
- In instances where a tracker is pre-approved for a proposed project based on estimated costs, the expenses eligible for rate recovery through the tracker should be capped at the initial cost estimate. Any cost overruns or amendments to the proposed budget would be open for review in a rate case, but would not be recoverable through the tracker.
- Once a tracker is approved, the utility periodically adjusts its rates through a summary proceeding to reflect the particular costs as they are incurred. The rate adjustment process, however, should not be automatic. In order to ensure the utility retains incentive to manage project costs efficiently, the utility should bear the burden each time it seeks a rate adjustment for a tracked expense of justifying the reasonableness of costs and the sufficiency of its efforts to minimize expenditures.

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[42] *See* Ind. Code §8-1-2-42.5.

Further or alternative measures may be appropriate to contain rate increases and prevent the imposition of excessive rates. The State Energy Policy, accordingly, should call for regulatory reform to address the proliferation of trackers and to protect ratepayers from excessive rate increases.

C. Competitive Procurement Standards Promote Efficiency

Under traditional regulation, capital investment by a utility in physical plant and equipment adds to the value of its rate base. A utility earns a return on its rate base.[43] When considering a substantial investment such as the construction of a new power plant or a retrofit of an existing plant to meet environmental requirements, accordingly, the utility has financial incentive to complete the project itself and create rate base assets yielding additional return through rates. In addition, the availability of rate trackers enhances, from the utility's perspective, the certainty and timing of the advantageous rate treatment.

From the perspective of ratepayers seeking cost-effectiveness, however, the utility undertaking a massive construction project may not be the most efficient approach. There is an active competitive wholesale market in which utilities can purchase power from a variety of suppliers in Indiana or in other states, on negotiated terms addressing the timeframe, reliability, volume requirements and pricing. Competitive purchases may be equally dependable and more economical than the self-build option favored by the utility. An array of competitive businesses, moreover, are engaged in the construction of power plants and energy facilities, and may be better positioned than the utility itself to manage project costs and avoid delays and overruns. Third party vendors and wholesale power providers, in other words, may be able to meet the given power needs more efficiently and at a more competitive price.

[43] *City of Evansville v. S. Ind. Gas and Electric Co.*, 167 Ind. App. 472, 480, 339 N.E.2d 562, 569 (1975); *L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 658, 351 N.E.2d 814, 820 (1976).

Regulation is supposed to act as a surrogate for competition, and will better serve that function by requiring utilities to secure resources at the best prices and terms available in the competitive market. For example, Duke Energy Indiana's decision to construct the Edwardsport power plant was not subject to competitive procurement standards and was not required to be cost-justified in comparison to available alternatives. Despite indications that projected energy needs could be satisfied more economically with purchased power and that third party construction could deliver a completed plant with reduced cost risk, Duke received pre-approval for a project initially estimated at a cost of $1.985 billion and eventually capped at an increased budget of $2.595 billion.[44]

In the 2014 session, the General Assembly recognized that competitive procurement imposes market discipline and promotes cost-effective outcomes for ratepayers, by passing a bill calling for consideration of competitive alternatives when a utility seeks regulatory approval for construction of a new power plant.[45] That step, however, does not require the utility to engage in an effective competitive procurement process and does not eliminate the utility bias in favor of its own construction projects. The State Energy Policy, accordingly, should affirmatively state that competitive procurement is a reasonable and necessary measure to ensure that the public receives the most efficient and cost-effective service available in the market.

D. <u>Rates Should be Based on Cost of Service</u>

One of the general principles of ratemaking calls for regulated rates to be based on the costs reasonably incurred by the utility in providing service to the given class of customers.[46]

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[44] *See Citizens Action Coalition v. PSI Energy, Inc.*, 894 N.E.2d 1055, 1061-62 (Ind. Ct. App. 2008); *In re Duke Energy Indiana*, Cause No. 43114 IGCC 4S1 (IURC 12/27/2012) at pp. 48, 75, *aff'd*, *Citizens Action Coalition v. Duke Energy*, 2014 WL 1092210 (Ind. Ct. App. 2014), *reh. pending*.

[45] *See* HEA 1162.

[46] The determination of costs for rate allocation purposes is typically conducted through a cost of service study. *See L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 697 n.35, 351 N.E.2d 814, 842 n.35 (1976);

Rates adhering to the cost-causation methodology are equitable, efficient and effective in sending accurate price signals to consumers. Rate subsidies, by which certain consumers pay rates above cost of service levels in order to reduce the rate obligations of other customers, are discriminatory and inefficient, and without imposition of the full cost consequences do not incentivize the favored class to conserve usage. Rates that reflect excessive costs incurred by the utility, furthermore, or that do not capture operational or corporate efficiencies available to the utility, impose higher rates than justified by the reasonable cost of providing service.

In several respects, utility rates in Indiana have drifted from the cost-based principle. As a result of rate policies instituted decades ago, a prevalent rate structure requires industrial consumers to subsidize the residential class of customers.[47] In other words, the utility return on industrial rates is higher than on residential rates, so that industrials pay above the level justified by cost of service in order to reduce the rates of residentials. As rates have increased steeply in recent years, furthermore, the impact has fallen disproportionately on the industrial class, as shown in the chart attached as Exhibit J.[48] Imposing higher rates on industrials in that fashion is misguided, as the rising pressure of energy costs impairs productivity, hinders economic development, and makes Indiana less attractive as a location for large employers. The better

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In re Indiana Michigan Power Co., Cause No. 44075 (IURC 2/13/2013) at pp. 110-18, *aff'd, Office of Util. Consumer Counselor v. Ind. Mich. Power Co.*, 2014 WL 934350 (Ind. Ct. App. 2014), *tr. pending*.

[47] *See, e.g., In re Indiana Michigan Power Co.*, Cause No. 44075 (IURC 2/13/2013) at pp. 117-18, *aff'd, Office of Util. Consumer Counselor v. Ind. Mich. Power Co.*, 2014 WL 934350 (Ind. Ct. App. 2014), *tr. pending* (approving reduction of existing rate subsidy by 50%); *In re PSI*, Cause 42359 (IURC May 18, 2004) at 103 (reducing subsidies is a significant step toward achieving equity among rate classes and is consistent with past Commission orders); *In re Richmond Power & Light*, Cause 40434 (IURC 03/19/97) at *7 (progress toward cost-based rates is a goal of the Commission, as has been stated in previous orders); *In re S. Ind. Gas and Elec. Co.*, Cause 37803 (IURC 02/05/1986) at * 292 (reaffirming Commission policy of reducing subsidies between customer classes in a prudent and consistent manner that avoids rate shock).

[48] Exhibit J data taken from U.S. Energy Information Administration. Data for 1997-2012 taken from *1990-2012 Average Price by State by Provider*, available at http://www.eia.gov/electricity/data/state/. Data for 2013 taken from *Electric Power Monthly* (with data for December 2013) (February 2014), Table 5.6.B, available at http://www.eia.gov/electricity/monthly/.

policy is to endorse the principle of cost-based rates and limit the industrial rate burden to the properly allocated costs incurred by the utility to serve the industrial class.

As rate cases have become more infrequent due to the increased use of trackers to adjust rates, there has been less scrutiny of the cost assumptions embedded in base rates. Rates premised on expense levels presented in a case many years ago may not reflect the actual or reasonable costs associated with the provision of current service. Efforts by the Commission to eliminate rate subsidies and move to fully cost-based rates have stalled due to excessive intervals between rate cases. Utilities, moreover, may adopt capital structures or follow financial policies set by parent holding companies that are out of keeping with efficient operations and least-cost performance. Under current Indiana law, the Commission has limited authority to regulate matters relating to utility management, corporate structure, holding company transactions and affiliated businesses.[49] The State Energy Policy should support stronger measures to limit rates to a cost foundation required by an efficient operation to provide reliable service at the least cost reasonably feasible.

Further departure from the principle of rates based on reasonable and efficient costs can arise from legislation or regulatory policies seeking to establish financial incentives in order to encourage a particular approach or option. In the 1990s, for example, utilities were granted favorable rate treatment if their environmental compliance plans provided for continued or

[49] *See* Ind. Code §§8-1-2-48, 8-1-2-49; *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 795-96, 801-02 (Ind. 2000) (addressing scope of Commission authority over unregulated affiliate of utility); *Ind. Bell Telephone Co. v. Ind. Util. Regulatory Commission*, 715 N.E.2d 351, 354-60 (Ind. 1999) (explaining limits on Commission authority over holding company transactions); *Intl. Broth. of Elec. Workers v. Indianapolis Power & Light Co.*, 920 N.E.2d 721, 725 n.3 (Ind. Ct. App.), *tr. denied*, 940 N.E.2d 822 (Ind. 2010) (noting utility secured substantial rate increase based on proposal to fund a trust to support retired employee benefits, then curtailed funding and cut benefits when acquired by a holding company while continuing to collect the increased rates).

increased use of Indiana coal.[50] More recently, legislation provided rate incentives to support the construction of "clean coal," coal gasification and similar facilities.[51] Utilities may seek further rate incentives in connection with energy efficiency programs.[52] From the perspective of industrial consumers, however, rate incentives to nudge utility behavior cannot be regarded as free money. The public is best served by a principle of cost efficiency, without added financial inducements aimed at supporting other ends.

[50] *See General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752, 763-67 (Ind. Ct. App. 1995) (striking down "Indiana coal" provisions as unconstitutional). *See also* Ind. Code §8-1-2-6.6; Ind. Code §§8-1-27-6(b)(6), 8(1)(D), 20.
[51] *See* Ind. Code §8-1-8.8-11; Ind. Code §8-1-37-13.
[52] *See* 170 Ind. Admin. Code §4-8-7.

VI. TASK FORCE ON ENERGY FOR ECONOMIC DEVELOPMENT

Because of the core importance of industrial jobs to the Indiana economy and the critical role energy costs play in industrial productivity, INDIEC proposes the establishment of a Task Force on Energy for Economic Development. The Task Force would include representatives of the IEDC, OED, INDIEC, IEA and possibly other stakeholders. The purpose would be to provide ongoing support as the State Energy Policy is implemented and to advise the Governor's Office on strategies to promote economic development through energy-related initiatives.

A. Rising Energy Costs Are an Impediment to Economic Development

Given that (1) industrial operations play a pivotal role in the Indiana economy, (2) electricity costs are of fundamental importance to energy-intensive industrial operations that are subject to strong competitive pressure, and (3) industrial electricity rates have been rising steeply and are expected to continue in that direction into the future, it is apparent that care and attention is warranted on an ongoing basis to address the impact of escalating electricity costs on economic development in Indiana. Where low energy costs were once an attraction for Indiana in competing for industrial jobs, the State's electricity cost profile is becoming a liability.

B. A Task Force on Energy for Economic Development Is Needed

In addition to the specific policy proposals included in this submission, INDIEC believes that an ongoing effort should be initiated to bring together industrial, utility and executive office personnel to address electricity costs as a factor in economic development in Indiana. A similar approach is underway in Michigan, where the Governor's Office has created an Energy-Intensive Industrial Rates Workgroup to provide input and guidance on strategies to mitigate industrial energy prices.[53] In Indiana, the appropriate participants would include at least INDIEC on behalf

[53] *See* Energy-Intensive Industrial Rates Workgroup, available at https://www.michigan.gov/energy/0,4580,7-230-67884---,00.html.

of industrials, the IEA for energy utilities, the IEDC with a focus on economic development, and the OED to address energy policy. Additional stakeholders may be included as appropriate. A collaborative Task Force consisting of those elements would provide ongoing assistance as the State Energy Policy is implemented and would serve as a continuing resource to the Governor's Office in addressing energy rates as an economic development factor for industrial operations in Indiana.

VII. ENERGY EFFICIENCY IS IMPORTANT TO LIMIT ENERGY COSTS

INDIEC supports a policy encouraging energy efficiency and efforts by consumers to reduce demand and conserve usage. The industrial opt-out provided for in recent legislation[54] advances that policy, because energy-intensive businesses are already subject to competitive pressure to mitigate the high cost of energy and are in the best position to determine how to do so most effectively within the context of their own business operations. Permitting utilities to impose a lost margins tracker, however, by which rates include continued profits for services no longer being provided due to reduced consumption, is contrary to sound ratemaking principles and counterproductive insofar as consumers are denied the full cost savings of their conservation efforts. Support for private generation projects, notably, advances the same policy favoring energy efficiency.

A. Energy Efficiency Is Advanced by the Industrial Opt-Out

The members of INDIEC have long been aware that efficient use of energy resources and diligent efforts to minimize consumption are important measures to control energy costs. INDIEC firmly supports the policy promoting energy efficiency, demand-side management and other efforts to reduce peak demand and encourage energy conservation. The recent legislation providing for an industrial opt-out from regulatory programs on energy efficiency advances that policy and supports industrial efforts to manage rising energy costs.

Independent of regulatory programs sponsored by utilities or subject to third party administration, industrial consumers have strong incentive to use energy efficiently and thereby reduce energy expenditures. Industrial operations are energy-intensive, making utilization of expensive energy resources a material factor in the cost of production. Industrials also face intense competition in national and global markets, requiring diligent attention to achieving

[54] *See* SEA 340.

operational efficiency and minimizing waste and unnecessary costs where possible. Industrials can and do implement energy efficiency measures in order to contain manageable costs in a major expense category, and have done so for many years. Given the precipitous rise in electricity rates in Indiana, the members of INDIEC have even stronger motivation to achieve efficiencies because energy costs are a key driver in their ability to compete effectively. Voluntary measures maximize efficiency and cost-effectiveness because the consumer does not have to pay administrative and program costs through utility rates.

Programs promoting use of products such as compact fluorescent bulbs and efficient household appliances, notably, are aimed primarily at residential consumers. The costs of such programs, accordingly, are not properly allocated to industrial ratepayers, and conversely the ability of industrials to opt out of regulatory programs should not affect the funding for such residential initiatives. Similarly, in contrast to programs providing for home energy audits to assist homeowners in adopting efficiency strategies of which they may not otherwise have been aware, industrials are highly sophisticated with respect to their energy-consuming operations and have ample capability and resources to evaluate efficiency measures. The industrial consumer is the expert in its own industrial process, understands its business operations, and is in the best position to identify and assess potential efficiencies.

An industrial opt-out, furthermore, allows for industrial participation in instances where an available program matches the needs of a given operation. Industrials choosing to receive program benefits will pay for such participation through rates, but importantly industrials that do not seek or receive such benefits will not be required to subsidize programs aimed at others. Large employers trying to remain competitive in Indiana despite the challenges of rapidly rising electricity costs should not be burdened with added rate increments associated with regulatory programs targeting the inefficiencies of other consumers.

Industrials also promote energy efficiency through other initiatives. Under demand-response programs, Indiana utilities call on industrials to reduce consumption at times of high demand by scaling back production or deploying alternative resources, thereby reducing peak usage and avoiding the need for utility investment in incremental supply capabilities. Similarly, industrials can purchase power under interruptible tariff provisions that authorize the utility to interrupt service at times of supply constraints or unusually high demand, again forestalling the need for the utility to build or purchase additional supply resources. By pursuing efficiencies in their own operations and structuring their purchases from utilities in a way that facilitates more efficient management of utility resources, industrials are actively involved in the promotion of energy efficiency.

B. A Lost Margins Tracker Is Contrary to Sound Policy

Under prior regulatory programs and the recent legislation on energy efficiency, utilities have been permitted to include in regulated rates an increment for lost margins attributable to power sales no longer being made by the utility due to consumer efficiency measures. The payment of lost margins in rates is a feature of utility-sponsored programs going forward and also remains a legacy obligation imposed on industrials that have opted out of participation in prior programs. The lost margins tracker for efficiency programs is not sound policy.

The recovery of lost margins through regulated rates in this context is properly regarded as another form of "tracker" because it permits a utility to secure rate adjustments to reflect a discrete set of circumstances without regard to all other conditions affecting the reasonableness of rate levels. A lost margins tracker allows the utility to target the revenue consequences of efficiency reductions in isolation, and to continue collecting a measure of historical profit margins whether or not the utility's overall financial performance warrants a rate change. Energy saved by one customer, for example, may be sold by a utility to the grid or to another customer, permitting the utility to mitigate or eliminate entirely any potential losses without imposing further charges in rates. Lost sales due to energy efficiency, moreover, may be offset by greater sales volume due to lower rates or new customers, or any revenue decrease may be balanced by cost savings in another aspect of the utility's operations, yet a lost margins tracker would permit rate recovery whether needed or not to meet the just and reasonable rate standard. For the same reasons explained supra Section V(A), excessive use of trackers have eroded regulatory protections in Indiana.

In several respects, furthermore, a lost margins tracker is contrary to established ratemaking principles. Rates are supposed to pay for service actually rendered, not for non-service,[55] yet a lost margins tracker requires ratepayers to pay for service no longer being provided by the utility. Ratepayers are not insurers of utility returns.[56] Utilities exist to provide service to the public; the public does not exist to maintain earnings for utilities. Utility investors are compensated for risk through the authorized rate of return.[57] The enterprise is not meant to be risk-free. Utilities are expected to manage fluctuations in demand, which occur constantly for a wide variety of reasons.[58] The law should not anticipate that every change in circumstance

[55] *Citizens Action Coalition v. N. Ind. Pub. Serv. Co.*, 485 N.E.2d 610, 613-14 (Ind. 1985), *cert. denied*, 476 U.S. 1137 (1986); *Ind. Gas Co. v. Office of Util. Consumer Counselor*, 675 N.E.2d 739, 743-44 (Ind. Ct. App.), *tr. den.*, 690 N.E.2d 1180 (Ind. 1997).
[56] *See Citizens Action Coalition v. N. Ind. Pub. Serv. Co.*, 485 N.E.2d 610, 615 (Ind. 1985), *cert. denied*, 476 U.S. 1137 (1986); *Ind. Gas Co. v. Office of Util. Consumer Counselor*, 675 N.E.2d 739, 744 (Ind. Ct. App.), *tr. den.*, 690 N.E.2d 1180 (Ind. 1997).
[57] *See City of Evansville v. S. Ind. Gas and Electric Co.*, 167 Ind. App. 472, 481, 339 N.E.2d 562, 570 (1975); *L.S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 660, 351 N.E.2d 814, 821 (1976).
[58] *See Ind. Gas Co. v. Office of Util. Consumer Counselor*, 575 N.E.2d 1044, 1052 (Ind. Ct. App. 1991) (noting the regulatory framework "requires the utility to bear losses and allows the utility to reap gains depending upon its managerial efficiency and how it weathers economic uncertainties after rates are fixed").

requires a rate adjustment. At any point that rate revenue falls below reasonably compensatory levels, the regulatory framework provides the utility with the remedy of filing a rate case to seek an increase.

Regulation is designed to act as a surrogate for competition, requiring the monopoly supplier to act as it would in a competitive market.[59] The Commission substitutes for the missing element of competition to prevent abuse of the utility's monopoly position, such as excessive prices or deficient service.[60] In a competitive market, a supplier would not be empowered to collect lost margins from customers for goods or services no longer being sold. If a consumer buys a fuel-efficient car, the gas station cannot demand continued payment of the profits from reduced gasoline sales. If a medical condition is abated by a pharmaceutical product, the manufacturer cannot force the patient to continue paying for medication that is no longer needed. Regulation, similarly, should not require consumers to preserve utility profit margins when energy efficiency measures are successful in reducing consumption.

A lost margins tracker has a tendency to foster misguided incentives. The purpose of efficiency programs is not only to achieve immediate reductions, but also to influence consumer conduct, altering usage patterns to decrease consumption. Financial incentives for utilities support that objective only indirectly, by encouraging the utility to institute programs that will, in turn, motivate consumers to use energy more efficiently. Recovery of lost margins through a rate tracker, however, provides that indirect incentive at the expense of the direct price signal to the consumer. The cost savings realized by consumers due to reduced usage, in that instance, are diluted by the continued need to pay margins to the utility for service no longer being rendered.

[59] *Citizens Action Coalition v. N. Ind. Pub. Serv. Co.*, 485 N.E.2d 610, 614-15 (Ind. 1985), *cert. denied*, 476 U.S. 1137 (1986).
[60] *N. Ind. Pub. Serv. Co. v. Citizens Action Coalition*, 548 N.E.2d 153, 159-60 (Ind. 1989); *Ind. Gas Co. v. Office of Util. Consumer Counselor*, 575 N.E.2d 1044, 1046 (Ind. Ct. App. 1991).

The direct incentive to the entity whose behavior the policy is oriented on influencing – the consumer – is greater if the full cost savings of reduced consumption are retained without funding an indirect incentive to the utility. The State Energy Policy, accordingly, should support energy efficiency without the imposition of a lost margin tracker.

C. Private Generation Promotes Energy Efficiency

The policy favoring development of private generation projects, as discussed supra Section IV, is reinforced by the policy supporting energy efficiency. Customer-specific energy installations that are tailored to the needs of an industrial operation will typically be efficient. New construction built to current standards can be expected to operate more efficiently than the aging coal-fired power plants that are prevalent in Indiana. Cogeneration facilities, waste-to-energy units and renewable energy sources are also environmentally friendly, reducing the emissions within the State associated with meeting energy demand.

One of the primary benefits of energy efficiency programs is to mitigate and postpone the need for new generation assets constructed at public expense by energy utilities. The same benefit also results from private generation projects, which utilize private enterprise to cover a portion of in-state energy demand and thereby correspondingly offset the magnitude of the power plant construction that the public must fund through utility rates.

VIII. CONCLUSION

In order to restore needed balance to the existing regulatory framework and mitigate the adverse impact of rapidly escalating electricity rates, INDIEC submits that the State Energy Policy should include the following elements:

1. A process should be established to allow industrial consumers to seek approval of flexible and alternative energy arrangements, under the oversight of the Commission;

2. A study should be conducted by the State Utility Forecasting Group analyzing alternative regulatory models in other states and the impact on energy costs, including jurisdictions that have implemented retail choice for electricity as well as traditionally regulated states;

3. The development of private generation resources should be promoted with measures eliminating regulatory obstacles and supporting a broader range of energy projects, through back-up, maintenance and supplemental service on reasonable terms, reasonable access to the grid, and protection from utility claims asserting monopoly service rights;

4. Regulatory standards and procedures should be revised to mitigate the impact of rate trackers, including requirements for more frequent rate cases, adjustments to authorized rate of return, caps on tracked expenses, and ratepayer protections in rate adjustment proceedings;

5. Stronger competitive procurement standards should be required when an electric utility is considering a major capital project to meet projected demand, in order to ensure that the public is served with the most cost-effective resources available;

6. Regulated energy rates should adhere to cost-based principles by eliminating rate subsidies, removing inefficiencies in utility costs embedded in rates, and precluding the use of rate incentives to support other objectives;
7. A Task Force on Energy for Economic Development should be established to provide ongoing support for continued efforts to promote economic development through energy-related initiatives;
8. Energy efficiency should be promoted consistent with the independent efforts of industrial consumers to reduce utilization of expensive energy resources, by endorsing the statutory opt-out for industrials from regulatory programs; and
9. Energy conservation and demand-side management should be encouraged by eliminating rate trackers for lost margins.

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Exhibit A

INDIEC

INDIANA INDUSTRIAL ENERGY CONSUMERS, INC.

INDIANA INDUSTRIAL ENERGY CONSUMERS, INC. (INDIEC)

The Indiana Industrial Energy Consumers, Inc. is an organization of large volume users of energy with manufacturing facilities in the State of Indiana. In any given year, INDIEC members consume between 30% and 35% of the energy used in the state. INDIEC represents, before all appropriate governmental bodies and other interested organizations within Indiana, the industrial viewpoint on legislative, regulatory, and administrative issues concerning the consumption of energy by industrial customers.

INDIEC WAS FOUNDED IN 1983 ON FIVE IMPORTANT PRINCIPLES

- Public utility rates to all classes should be based on cost of service principles.
- Public utilities must be provided with the opportunity to earn a fair rate of return on their investment.
- Public utility rates should reflect efficient operation.
- State regulatory processes must be responsible and timely.
- Administrative, legislative and regulatory bodies should actively pursue energy policies that preserve the existing industrial and economic base and related employment and promote economic growth in the State of Indiana.

MEMBERS	**MEMBERS**
AIR LIQUIDE	
AIR PRODUCTS AND CHEMICALS, INC.	ROLLS-ROYCE CORPORATION
ALCOA	SAINT-GOBAIN CONTAINERS
ALLISON TRANSMISSION	SUBARU OF INDIANA AUTOMOTIVE, INC.
ARCELOR MITTAL	TATE & LYLE
BP	TOYOTA MOTOR MANUFACTURING INDIANA
CHRYSLER CORPORATION	U.S. GYPSUM
ELI LILLY AND COMPANY	VERTELLUS SPECIALTIES, INC.
GENERAL MOTORS CORPORATION	
HAYNES INTERNATIONAL, INC.	**AFFILIATE MEMBERS**
HONDA OF AMERICA MFG, INC.	INDIANA CAST METALS ASSOCIATION
INGREDION (formerly National Starch)	BP CANADA ENERGY MARKETING CORP
LEHIGH HANSON	CENTERPOINT ENERGY
LINDE GROUP	EDF ENERGY SERVICES
MARATHON PETROLEUM COMPANY LLC	SHELL ENERGY NORTH AMERICA
NLMK INDIANA (formerly Beta Steel)	EAST CENTRAL EDUCATIONAL SERVICE CENTER
NOVELIS CORPORATION	NORTHWEST INDIANA EDUCATION SERVICE CENTER
PRAXAIR, INC.	

Exhibit B

Average Industrial Electricity Prices by State

	State Rank - Lowest to Highest			Industrial Price - Cents per kwh		
	2013	2012	2003	2013	2012	2003
State						
Washington	1	1	25	4.22	4.13	4.76
Oklahoma	2	3	21	5.34	5.09	4.59
Montana	3	4	9	5.37	5.10	4.01
Kentucky	4	6	1	5.40	5.35	3.21
Iowa	5	5	12	5.66	5.30	4.16
Illinois	6	13	29	5.73	5.80	4.91
Oregon	7	10	23	5.86	5.59	4.63
Arkansas	8	12	11	5.88	5.76	4.04
Utah	8	11	3	5.88	5.62	3.79
District of Columbia	10	7	38	5.89	5.46	5.61
Louisiana	10	2	37	5.89	4.76	5.57
South Carolina	12	17	8	5.92	6.02	4.00
Texas	13	9	34	5.93	5.57	5.27
Alabama	14	19	7	5.99	6.22	3.98
Ohio	15	20	26	6.10	6.24	4.79
Georgia	16	16	10	6.11	5.98	4.02
Idaho	17	8	12	6.12	5.48	4.16
Missouri	18	15	19	6.14	5.89	4.49
West Virginia	19	22	4	6.24	6.33	3.81
New York	20	30	41	6.29	6.70	7.14
New Mexico	21	14	30	6.32	5.83	4.95
North Carolina	22	24	26	6.34	6.42	4.79
Wyoming	23	18	2	6.41	6.03	3.65
Tennessee	24	34	16	6.44	7.08	4.29
Mississippi	25	20	18	6.45	6.24	4.48
Nevada	26	25	42	6.52	6.48	7.30
Indiana	27	23	5	6.59	6.34	3.92
Virginia	28	31	15	6.65	6.72	4.23
Arizona	29	26	35	6.69	6.53	5.38
South Dakota	30	29	20	6.93	6.57	4.51
Pennsylvania	31	36	39	7.00	7.23	6.14
Minnesota	32	27	17	7.06	6.54	4.36
Kansas	33	35	22	7.07	7.09	4.61
North Dakota	34	28	6	7.20	6.55	3.96
Colorado	35	32	32	7.22	6.95	5.10
Nebraska	35	33	14	7.22	7.01	4.18
Wisconsin	37	37	24	7.54	7.34	4.71
Florida	38	40	36	7.70	8.04	5.41
Michigan	39	38	31	7.85	7.73	4.96
Maine	40	39	40	8.27	7.87	6.35
Maryland	41	41	28	8.38	8.12	4.89
Delaware	42	42	33	8.50	8.34	5.15
Vermont	43	43	46	10.14	9.96	8.05
New Jersey	44	44	43	10.77	10.54	7.47
California	45	45	50	11.28	10.73	9.85
New Hampshire	46	47	49	11.37	11.82	9.39
Rhode Island	47	46	47	11.62	10.86	9.06
Connecticut	48	48	45	12.66	12.76	7.92
Massachusetts	49	49	48	13.13	12.91	9.11
Alaska	50	50	44	15.66	16.75	7.86
Hawaii	51	51	51	29.81	30.77	12.20

Rank lowest electricity price to highest electricity price

Sources: US Energy Information Administration - Electric Power Monthly, Table 5.6B, February 2014 and March 2005

Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through Dec
(Cents per Kilowatthour)

Census Division and State	Residential		Commercial[1]		Industrial[1]		Transportation[1]		All Sectors	
	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003
New England	**12**	**11.71**	**10.76**	**10.34**	**7.8**	**8.37**	**5.8**	**5.55**	**10.64**	**10.45**
Connecticut	11.64	11.31	9.81	9.99	8.16	7.92	7.25	7.76	10.28	10.17
Maine	12.63	12.37	11.36	10.34	3.56	6.35	--	--	9.53	9.79
Massachusetts	11.85	11.68	11.05	10.48	8.49	9.11	5.12	4.09	10.85	10.63
New Hampshire	12.51	11.98	11	10.44	10.04	9.39	--	--	11.39	10.8
Rhode Island	12.19	11.62	10.78	10	8.58	9.06	--	--	10.94	10.47
Vermont	13.07	12.82	11.44	11.29	7.93	8.05	--	--	11.08	10.98
Middle Atlantic	**11.85**	**11.61**	**10.54**	**10.62**	**6.35**	**6.63**	**7**	**8.93**	**10.05**	**10.07**
New Jersey	11.24	10.69	9.6	9.25	8.67	7.47	10.91	9.72	10.07	9.46
New York	14.58	14.31	12.1	12.93	6.23	7.14	6.57	9.37	11.97	12.44
Pennsylvania	9.66	9.55	8.72	8.07	5.86	6.14	7.32	7.21	8.09	7.98
East North Central	**8.37**	**8.15**	**7.4**	**7.21**	**4.65**	**4.64**	**6.11**	**5.99**	**6.67**	**6.54**
Illinois	8.51	8.38	7.51	7.22	4.73	4.91	5.69	5.89	6.9	6.88
Indiana	7.32	7.04	6.29	6.13	4.14	3.92	8.75	8.37	5.59	5.37
Michigan	8.55	8.35	7.73	7.55	4.91	4.96	8.09	8.21	7.06	6.85
Ohio	8.47	8.27	7.66	7.6	4.74	4.79	9.21	6.17	6.82	6.75
Wisconsin	9.1	8.67	7.22	6.97	4.91	4.71	--	--	6.9	6.64
West North Central	**7.65**	**7.42**	**6.24**	**6.02**	**4.49**	**4.34**	**4.91**	**--**	**6.2**	**6.03**
Iowa	9.06	8.57	6.8	6.24	4.39	4.16	--	--	6.47	6.11
Kansas	7.82	7.71	6.63	6.42	4.59	4.61	--	--	6.44	6.35
Minnesota	8.06	7.65	6.32	6.12	4.7	4.36	6.77	--	6.3	6.01
Missouri	7.06	6.96	5.86	5.78	4.39	4.49	4.23	--	6.04	6.02
Nebraska	6.91	6.87	5.86	5.81	4.25	4.18	--	--	5.66	5.64
North Dakota	6.77	6.49	6.11	5.64	4.2	3.96	--	--	5.76	5.47
South Dakota	7.64	7.47	6.64	6.04	4.6	4.51	--	--	6.6	6.35
South Atlantic	**8.34**	**8.1**	**7.07**	**6.7**	**4.59**	**4.47**	**5.26**	**6.15**	**7.05**	**6.77**
Delaware	8.8	8.59	7.55	7.31	4.99	5.15	--	--	7.27	6.96
District of Columbia	8.14	7.66	7.39	7.43	5.1	5.61	2.57	7.62	7.32	7.43
Florida	8.95	8.55	7.57	7.13	5.86	5.41	7.5	7.2	8.12	7.72
Georgia	7.94	7.7	6.97	6.66	4.45	4.02	5.12	4.81	6.65	6.32
Maryland	8	7.73	9.02	6.95	4.51	4.89	6.24	5.78	7.13	6.45
North Carolina	8.44	8.32	6.76	6.65	4.89	4.79	--	--	6.99	6.86
South Carolina	8.05	8.01	6.97	6.81	4.14	4	--	--	6.22	6.08
Virginia	7.99	7.76	5.88	5.74	4.3	4.23	6.25	5.46	6.44	6.27
West Virginia	6.23	6.24	5.46	5.45	3.83	3.81	5.75	--	5.13	5.13
East South Central	**7.09**	**6.78**	**6.89**	**6.52**	**4.04**	**3.86**	**11.75**	**--**	**5.83**	**5.55**
Alabama	7.55	7.39	7.16	6.85	4.21	3.98	--	--	6.09	5.88
Kentucky	6.08	5.81	5.6	5.37	3.3	3.21	--	--	4.6	4.42
Mississippi	8.17	7.6	7.93	7.25	4.8	4.48	--	--	6.98	6.46
Tennessee	6.88	6.55	7.03	6.68	4.48	4.29	11.75	--	6.13	5.84
West South Central	**8.98**	**8.61**	**7.52**	**7.44**	**5.4**	**5.14**	**7.07**	**6.59**	**7.36**	**7.13**
Arkansas	7.44	7.24	5.84	5.54	4.19	4.04	--	--	5.77	5.57
Louisiana	8.09	7.84	7.56	7.42	5.82	5.57	7.15	7.31	7.14	6.93
Oklahoma	7.67	7.47	6.66	6.38	4.72	4.59	--	--	6.53	6.35
Texas	9.6	9.16	7.84	7.84	5.57	5.27	7.05	6.57	7.75	7.5
Mountain	**8.23**	**8.02**	**7.13**	**6.85**	**5.08**	**5.01**	**6.25**	**6.79**	**6.9**	**6.71**
Arizona	8.47	8.35	7.5	7.09	5.5	5.38	--	--	7.59	7.34
Colorado	8.32	8.14	6.92	6.6	5.32	5.1	5.81	7.31	7	6.77
Idaho	6.08	6.24	5.34	5.56	3.83	4.16	--	--	4.97	5.22

Source: U.S. Energy Information Administration
Electric Power Monthly, Table 5.6B (March 2005)
Available at: http://www.eia.gov/electricity/monthly/backissues.html

Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2013 and 2012 (Cents per Kilowatthour)

Census Division and State	Residential December 2013 YTD	Residential December 2012 YTD	Commercial December 2013 YTD	Commercial December 2012 YTD	Industrial December 2013 YTD	Industrial December 2012 YTD	Transportation December 2013 YTD	Transportation December 2012 YTD	All Sectors December 2013 YTD	All Sectors December 2012 YTD
New England	16.20	15.71	14.08	13.68	12.17	11.83	9.17	6.68	14.48	14.02
Connecticut	17.58	17.34	14.64	14.65	12.68	12.67	10.31	9.69	15.68	15.54
Maine	14.35	14.66	11.72	11.53	8.32	7.98	–	–	11.67	11.81
Massachusetts	15.73	14.91	14.51	13.84	13.09	12.57	NM	4.91	14.51	13.79
New Hampshire	16.36	16.07	13.52	13.36	11.41	11.83	–	–	14.31	14.19
Rhode Island	15.47	14.40	13.08	11.87	11.87	10.68	13.00	8.28	13.91	12.74
Vermont	17.15	17.01	14.84	14.32	10.19	9.98	–	–	14.46	14.22
Middle Atlantic	15.72	15.27	13.00	12.97	7.25	7.49	12.17	12.50	12.90	12.75
New Jersey	15.72	15.78	12.80	12.78	10.71	10.52	10.43	9.77	13.70	13.68
New York	18.84	17.62	15.23	15.06	6.29	6.70	13.63	14.20	15.62	15.15
Pennsylvania	12.82	12.75	9.26	9.44	7.00	7.23	7.62	8.07	9.63	9.91
East North Central	12.01	12.06	9.61	9.46	6.57	6.51	5.71	6.33	9.35	9.27
Illinois	10.25	11.37	7.86	7.99	5.73	5.80	5.44	6.15	7.99	8.40
Indiana	10.84	10.53	8.48	9.14	6.59	6.34	9.57	8.96	8.53	8.29
Michigan	14.59	14.13	11.07	10.93	7.78	7.62	9.92	8.08	11.26	10.98
Ohio	11.91	11.76	9.38	9.47	6.10	6.24	6.61	6.98	9.16	9.12
Wisconsin	13.70	13.19	10.84	10.51	7.54	7.34	–	–	10.64	10.28
West North Central	10.95	10.59	8.95	8.48	6.60	6.28	8.78	7.72	8.96	8.54
Iowa	11.15	10.82	8.47	8.01	5.66	5.30	–	–	8.12	7.71
Kansas	11.56	11.24	9.54	9.24	7.07	7.09	–	–	9.57	9.33
Minnesota	11.94	11.35	9.53	8.84	7.06	6.54	9.79	8.67	9.52	8.86
Missouri	10.52	10.17	8.72	8.20	6.14	5.89	7.90	6.97	8.96	8.53
Nebraska	10.31	10.04	8.62	8.38	7.22	7.01	–	–	8.69	8.37
North Dakota	9.10	9.06	8.31	8.02	7.20	8.55	–	–	8.19	7.83
South Dakota	10.26	10.07	8.44	8.10	6.93	6.57	–	–	8.83	8.49
South Atlantic	11.37	11.38	9.39	9.37	6.48	6.55	8.66	8.44	9.73	9.73
Delaware	13.01	13.58	10.26	10.13	8.50	8.36	–	–	10.98	11.06
District of Columbia	12.56	12.28	11.93	12.02	5.89	5.46	9.58	9.01	11.85	11.85
Florida	11.36	11.42	9.49	9.66	7.68	8.04	8.69	8.45	10.30	10.44
Georgia	11.24	11.17	9.64	9.58	6.11	5.98	8.03	7.65	9.53	9.37
Maryland	13.24	12.84	10.70	10.43	8.36	8.09	8.48	8.29	11.65	11.28
North Carolina	10.91	10.91	8.73	8.66	6.34	6.42	7.94	7.88	9.18	9.15
South Carolina	11.82	11.77	9.82	9.63	5.92	6.02	–	–	9.14	9.10
Virginia	10.93	11.08	8.05	8.08	6.65	6.72	8.17	8.51	9.01	9.07
West Virginia	9.52	9.85	8.16	8.42	6.20	6.33	8.68	8.66	7.91	8.14
East South Central	10.42	10.32	9.82	9.87	5.96	6.11	11.46	11.28	8.71	8.58
Alabama	11.27	11.40	10.50	10.63	5.99	6.22	–	–	9.02	9.18
Kentucky	9.71	9.43	8.50	8.73	5.40	5.35	–	–	7.54	7.26
Mississippi	10.82	10.26	10.21	9.33	6.45	6.24	–	–	9.15	8.60
Tennessee	10.04	10.10	10.01	10.31	6.44	7.08	11.46	11.28	9.22	9.27
West South Central	10.73	10.30	8.11	7.99	5.66	5.39	10.02	10.30	8.47	8.11
Arkansas	9.51	9.30	7.98	7.71	5.88	5.76	NM	11.23	7.62	7.62
Louisiana	9.39	8.37	8.94	7.75	5.89	4.76	9.45	8.72	8.00	6.90
Oklahoma	9.62	9.51	7.71	7.32	5.34	5.09	–	–	7.81	7.54
Texas	11.37	10.98	8.03	8.16	5.93	5.57	10.12	10.54	8.77	8.55
Mountain	11.32	10.94	9.37	8.99	6.46	6.18	10.47	9.62	9.18	8.82
Arizona	11.74	11.29	9.87	9.53	6.69	6.53	–	–	10.16	9.81
Colorado	11.87	11.46	9.87	9.39	7.22	6.95	10.55	9.69	9.80	9.39
Idaho	9.37	8.67	7.40	6.86	6.12	5.48	–	–	7.61	6.92
Montana	10.38	10.08	9.52	9.13	5.37	5.10	–	–	8.58	8.25
Nevada	11.89	11.83	9.02	8.83	6.52	6.48	8.47	8.40	9.04	8.95
New Mexico	11.69	11.37	9.78	9.32	6.32	5.83	–	–	9.24	8.83
Utah	10.42	9.93	8.37	8.06	5.88	5.62	10.68	9.79	8.18	7.84
Wyoming	10.18	9.85	8.60	8.24	6.41	6.03	–	–	7.55	7.19
Pacific Contiguous	13.60	12.94	12.77	11.92	8.20	7.78	7.72	7.21	12.07	11.38
California	16.39	15.34	14.57	13.41	11.17	10.49	7.68	7.17	14.57	13.53
Oregon	9.94	9.80	8.39	8.31	5.86	5.59	8.88	8.24	8.39	8.21
Washington	8.67	8.53	7.76	7.68	4.22	4.13	8.29	8.06	7.06	6.94
Pacific Noncontiguous	28.59	28.76	25.52	25.50	26.06	26.99	–	–	26.81	26.96
Alaska	16.19	17.88	15.62	14.93	15.77	16.82	–	–	16.52	16.33
Hawaii	36.99	37.34	34.06	34.88	29.87	30.82	–	–	33.27	34.04
U.S. Total	12.12	11.88	10.29	10.09	6.82	6.67	10.28	10.21	10.08	9.84

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values for 2012 are final. Values for 2013 are preliminary estimates based on a cutoff model sample.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.

Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

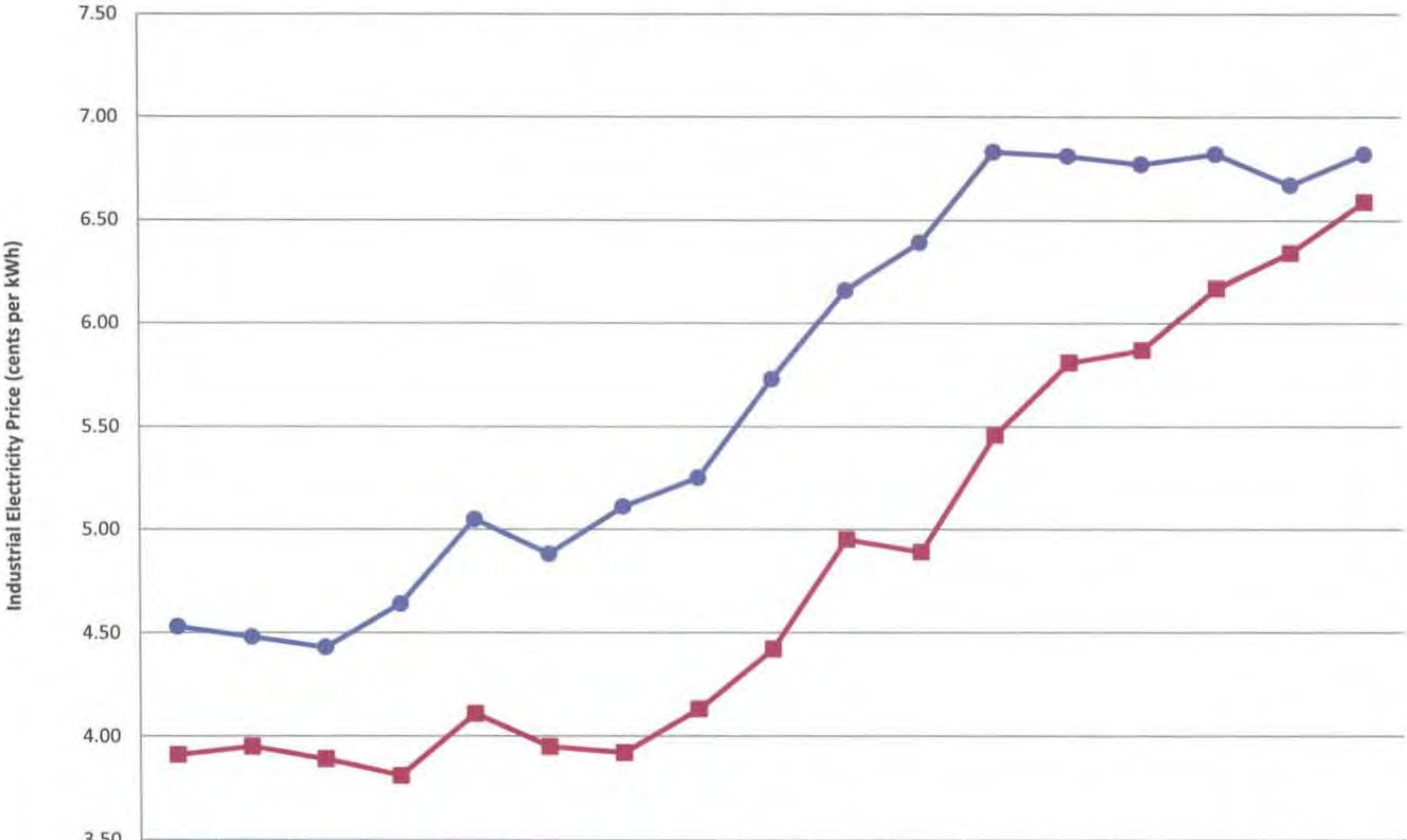
Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report.

Source: U.S. Energy Information Administration, Electric Power Monthly, available at http://www.eia.gov/electricity/monthly/

Exhibit C

Industrial Electricity Prices for Indiana and U.S. Total

(1997-2013)



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
IN	3.91	3.95	3.89	3.81	4.11	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.34	6.59
US Total	4.53	4.48	4.43	4.64	5.05	4.88	5.11	5.25	5.73	6.16	6.39	6.83	6.81	6.77	6.82	6.67	6.82

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2012	IN	Total Electric Industry	10.53	9.14	6.34	9.56	NA	8.29
2012	**US**	**Total Electric Industry**	**11.88**	**10.09**	**6.67**	**10.21**	**NA**	**9.84**
2011	IN	Total Electric Industry	10.06	8.77	6.17	9.74	NA	8.01
2011	**US**	**Total Electric Industry**	**11.72**	**10.23**	**6.82**	**10.46**	**NA**	**9.90**
2010	IN	Total Electric Industry	9.56	8.38	5.87	9.21	NA	7.67
2010	**US**	**Total Electric Industry**	**11.54**	**10.19**	**6.77**	**10.57**	**NA**	**9.83**
2009	IN	Total Electric Industry	9.50	8.32	5.81	9.65	NA	7.62
2009	**US**	**Total Electric Industry**	**11.51**	**10.17**	**6.81**	**10.65**	**NA**	**9.82**
2008	IN	Total Electric Industry	8.87	7.82	5.46	9.60	NA	7.09
2008	**US**	**Total Electric Industry**	**11.26**	**10.36**	**6.83**	**10.74**	**NA**	**9.74**
2007	IN	Total Electric Industry	8.26	7.29	4.89	10.09	NA	6.50
2007	**US**	**Total Electric Industry**	**10.65**	**9.65**	**6.39**	**9.70**	**NA**	**9.13**
2006	IN	Total Electric Industry	8.22	7.21	4.95	9.66	NA	6.46
2006	**US**	**Total Electric Industry**	**10.40**	**9.46**	**6.16**	**9.54**	**NA**	**8.90**
2005	IN	Total Electric Industry	7.50	6.57	4.42	9.14	NA	5.88
2005	**US**	**Total Electric Industry**	**9.45**	**8.67**	**5.73**	**8.57**	**NA**	**8.14**
2004	IN	Total Electric Industry	7.30	6.31	4.13	8.76	NA	5.58
2004	**US**	**Total Electric Industry**	**8.95**	**8.17**	**5.25**	**7.18**	**NA**	**7.61**
2003	IN	Total Electric Industry	7.04	6.12	3.92	8.36	NA	5.37
2003	**US**	**Total Electric Industry**	**8.72**	**8.03**	**5.11**	**7.54**	**NA**	**7.44**
2002	IN	Total Electric Industry	6.91	5.98	3.95	NA	9.75	5.34
2002	**US**	**Total Electric Industry**	**8.44**	**7.89**	**4.88**	**NA**	**6.75**	**7.20**
2001	IN	Total Electric Industry	6.92	5.29	4.11	NA	9.06	5.30
2001	**US**	**Total Electric Industry**	**8.58**	**7.92**	**5.05**	**NA**	**7.20**	**7.29**
2000	IN	Total Electric Industry	6.87	5.93	3.81	NA	9.37	5.18
2000	**US**	**Total Electric Industry**	**8.24**	**7.43**	**4.64**	**NA**	**6.56**	**6.81**
1999	IN	Total Electric Industry	6.96	6.05	3.89	NA	9.70	5.29
1999	**US**	**Total Electric Industry**	**8.16**	**7.26**	**4.43**	**NA**	**6.35**	**6.64**
1998	IN	Total Electric Industry	7.01	6.08	3.95	NA	9.83	5.34
1998	**US**	**Total Electric Industry**	**8.26**	**7.41**	**4.48**	**NA**	**6.63**	**6.74**
1997	IN	Total Electric Industry	6.94	6.04	3.91	NA	9.44	5.29
1997	**US**	**Total Electric Industry**	**8.43**	**7.59**	**4.53**	**NA**	**6.91**	**6.85**

Source: U.S. Energy Information Administration "1990-2012 Average Price by State by Provider"
available at **http://www.eia.gov/electricity/data/state/**

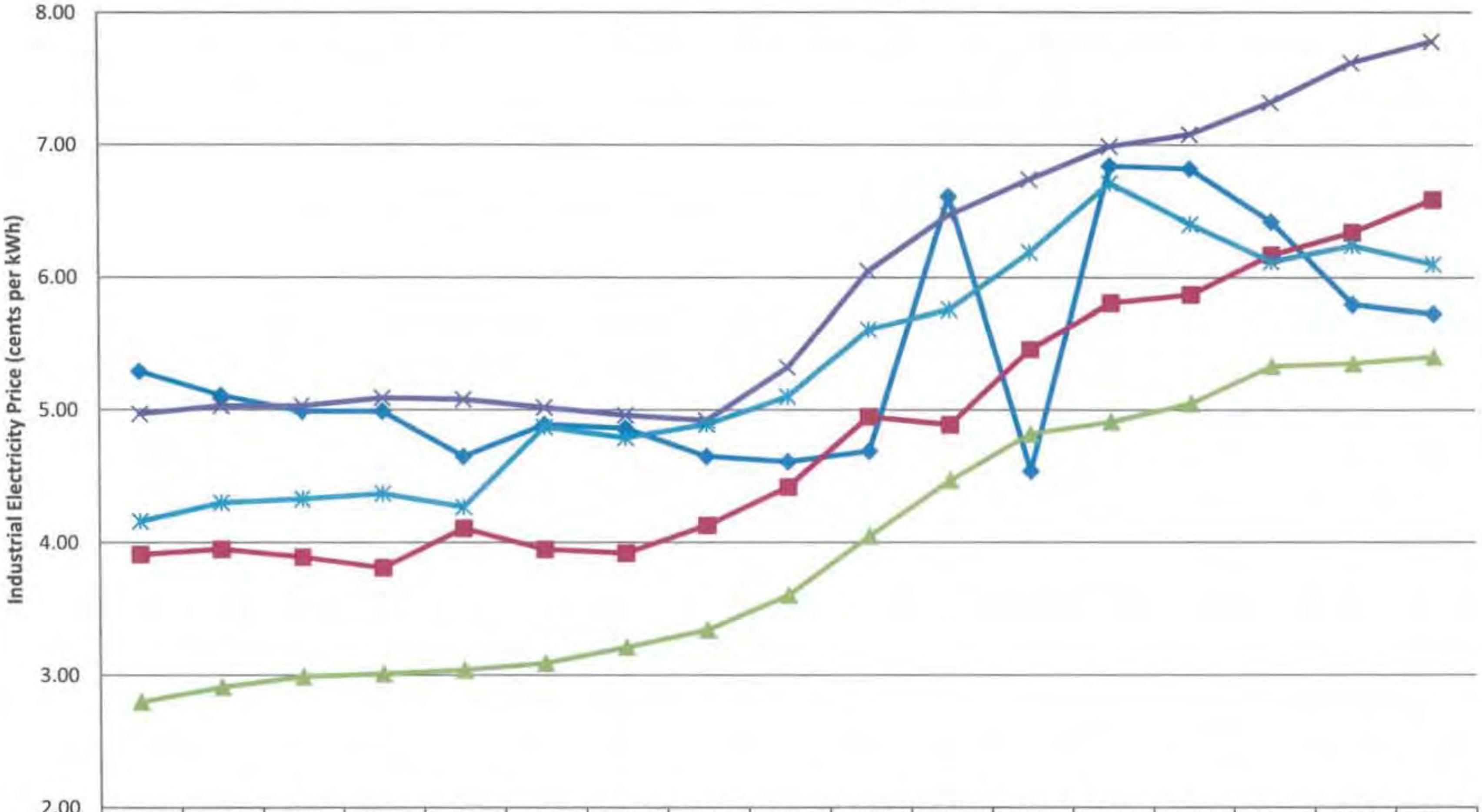
Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2013 and 2012 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD
New England	16.20	15.71	14.08	13.68	12.17	11.83	9.17	6.68	14.48	14.02
Connecticut	17.58	17.34	14.64	14.65	12.68	12.67	10.31	9.69	15.68	15.54
Maine	14.35	14.66	11.72	11.53	8.32	7.98	–	–	11.87	11.81
Massachusetts	15.73	14.91	14.51	13.84	13.09	12.57	NM	4.91	14.51	13.79
New Hampshire	16.36	16.07	13.52	13.36	11.41	11.83	–	–	14.31	14.19
Rhode Island	15.47	14.40	13.08	11.87	11.87	10.68	13.00	8.28	13.91	12.74
Vermont	17.15	17.01	14.64	14.32	10.19	9.98	–	–	14.46	14.22
Middle Atlantic	15.72	15.27	13.00	12.97	7.25	7.49	12.17	12.50	12.90	12.75
New Jersey	15.72	15.78	12.80	12.78	10.71	10.52	10.43	9.77	13.70	13.68
New York	18.84	17.62	15.23	15.06	6.29	6.70	13.63	14.20	15.62	15.15
Pennsylvania	12.82	12.75	9.26	9.44	7.00	7.23	7.82	8.07	9.83	0.91
East North Central	12.01	12.05	9.51	9.46	6.57	6.51	5.71	6.33	9.33	9.27
Illinois	10.25	11.37	7.88	7.99	5.73	5.80	5.44	6.15	7.99	8.40
Indiana	10.84	10.53	9.48	9.14	6.59	6.34	9.87	9.56	8.63	8.29
Michigan	14.59	14.13	11.07	10.93	7.78	7.62	9.92	8.08	11.26	10.98
Ohio	11.91	11.76	9.38	9.47	6.10	6.24	6.61	6.98	9.16	9.12
Wisconsin	13.70	13.19	10.84	10.51	7.54	7.34	–	–	10.64	10.28
West North Central	10.95	10.59	8.95	8.48	6.60	6.28	8.78	7.72	8.96	8.54
Iowa	11.15	10.82	8.47	8.01	5.66	5.30	–	–	8.12	7.71
Kansas	11.56	11.24	9.54	9.24	7.07	7.09	–	–	9.57	9.33
Minnesota	11.94	11.35	9.53	8.84	7.06	6.54	9.79	8.67	9.52	8.86
Missouri	10.52	10.17	8.72	8.20	6.14	5.89	7.90	6.97	8.96	8.53
Nebraska	10.31	10.04	8.62	8.38	7.22	7.01	–	–	8.69	8.37
North Dakota	9.10	9.06	8.31	8.02	7.20	6.55	–	–	8.19	7.83
South Dakota	10.26	10.07	8.44	8.10	6.93	6.57	–	–	8.83	8.49
South Atlantic	11.37	11.38	9.39	9.37	6.48	6.55	8.66	8.44	9.73	9.73
Delaware	13.01	13.58	10.26	10.13	8.50	8.36	–	–	10.98	11.06
District of Columbia	12.56	12.28	11.93	12.02	5.89	5.46	9.58	9.01	11.85	11.85
Florida	11.36	11.42	9.49	9.66	7.68	8.04	8.69	8.45	10.30	10.44
Georgia	11.24	11.17	9.84	9.58	6.11	5.98	8.03	7.65	9.53	9.37
Maryland	13.24	12.84	10.70	10.43	8.36	8.09	8.48	8.29	11.65	11.28
North Carolina	10.91	10.91	8.73	8.66	6.34	6.42	7.94	7.88	9.18	9.15
South Carolina	11.82	11.77	9.82	9.63	5.92	6.02	–	–	9.14	9.10
Virginia	10.93	11.08	8.05	8.08	6.65	6.72	8.17	8.51	9.01	9.07
West Virginia	9.52	9.85	8.16	8.42	6.20	6.33	8.68	8.66	7.91	8.14
East South Central	10.42	10.32	9.82	9.87	5.96	6.11	11.46	11.28	8.71	8.58
Alabama	11.27	11.40	10.50	10.63	5.99	6.22	–	–	9.02	9.18
Kentucky	9.71	9.43	8.50	8.73	5.40	5.35	–	–	7.54	7.26
Mississippi	10.82	10.26	10.21	9.33	6.45	6.24	–	–	9.15	8.60
Tennessee	10.04	10.10	10.01	10.31	6.44	7.08	11.46	11.28	9.22	9.27
West South Central	10.73	10.30	8.11	7.99	5.86	5.39	10.02	10.30	8.47	8.11
Arkansas	9.51	9.30	7.98	7.71	5.88	5.76	NM	11.23	7.82	7.62
Louisiana	9.39	8.37	8.94	7.75	5.89	4.76	9.45	8.72	8.00	6.90
Oklahoma	9.62	9.51	7.71	7.32	5.34	5.09	–	–	7.81	7.54
Texas	11.37	10.98	8.03	8.16	5.93	5.57	10.12	10.54	8.77	8.55
Mountain	11.32	10.94	9.37	8.99	6.46	6.18	10.47	9.62	9.18	8.82
Arizona	11.74	11.29	9.87	9.53	6.69	6.53	–	–	10.16	9.81
Colorado	11.87	11.46	9.87	9.39	7.22	6.95	10.55	9.69	9.80	9.39
Idaho	9.37	8.67	7.40	6.86	6.12	5.48	–	–	7.61	6.92
Montana	10.38	10.08	9.52	9.13	5.37	5.10	–	–	8.58	8.25
Nevada	11.89	11.83	9.02	8.83	6.52	6.48	8.47	8.40	9.04	8.95
New Mexico	11.69	11.37	9.78	9.32	6.32	5.83	–	–	9.24	8.83
Utah	10.42	9.93	8.37	8.06	5.88	5.62	10.68	9.79	8.18	7.84
Wyoming	10.18	9.85	8.60	8.24	6.41	6.03	–	–	7.55	7.19
Pacific Contiguous	13.60	12.94	12.77	11.92	8.20	7.78	7.72	7.21	12.07	11.38
California	16.39	15.34	14.57	13.41	11.17	10.49	7.68	7.17	14.57	13.53
Oregon	9.94	9.80	8.39	8.31	5.86	5.59	8.88	8.24	8.39	8.21
Washington	8.67	8.53	7.76	7.68	4.22	4.13	8.29	8.06	7.06	6.94
Pacific Noncontiguous	28.59	28.76	25.52	25.50	26.08	26.99	–	–	26.61	26.96
Alaska	18.19	17.88	15.62	14.93	15.77	16.82	–	–	16.52	16.33
Hawaii	36.99	37.34	34.06	34.88	29.87	30.82	–	–	33.27	34.04
U.S. Total	12.12	11.88	10.29	10.09	6.82	6.67	10.28	10.21	10.08	9.84

Source: U.S. Energy Information Administration, Electric Power Monthly, February 2014, available at http://www.eia.gov/electricity/monthly/

Exhibit D

Industrial Electricity Prices of Indiana and Neighboring States



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
IL	5.29	5.11	4.99	4.99	4.65	4.89	4.86	4.65	4.61	4.69	6.61	4.54	6.84	6.82	6.42	5.80	5.73
IN	3.91	3.95	3.89	3.81	4.11	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.34	6.59
KY	2.80	2.91	2.99	3.01	3.04	3.09	3.21	3.34	3.60	4.05	4.47	4.82	4.91	5.05	5.33	5.35	5.40
MI	4.97	5.03	5.03	5.09	5.08	5.02	4.96	4.92	5.32	6.05	6.47	6.74	6.99	7.08	7.32	7.62	7.78
OH	4.16	4.30	4.33	4.37	4.27	4.87	4.79	4.89	5.10	5.61	5.76	6.19	6.71	6.40	6.12	6.24	6.10

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
1997	IL	Total Electric Industry	10.43	7.93	5.29	NA	6.84	7.71
1997	IN	Total Electric Industry	6.94	6.04	3.91	NA	9.44	5.29
1997	KY	Total Electric Industry	5.58	5.29	2.80	NA	4.64	4.03
1997	MI	Total Electric Industry	8.57	7.84	4.97	NA	10.88	7.04
1997	OH	Total Electric Industry	8.63	7.67	4.16	NA	6.12	6.25
1998	IL	Total Electric Industry	9.85	7.77	5.11	NA	6.80	7.46
1998	IN	Total Electric Industry	7.01	6.08	3.95	NA	9.83	5.34
1998	KY	Total Electric Industry	5.61	5.30	2.91	NA	4.67	4.16
1998	MI	Total Electric Industry	8.67	7.81	5.03	NA	10.74	7.09
1998	OH	Total Electric Industry	8.70	7.67	4.30	NA	6.07	6.38
1999	IL	Total Electric Industry	8.83	7.38	4.99	NA	5.95	6.96
1999	IN	Total Electric Industry	6.96	6.05	3.89	NA	9.70	5.29
1999	KY	Total Electric Industry	5.58	5.27	2.99	NA	4.55	4.17
1999	MI	Total Electric Industry	8.73	7.85	5.03	NA	10.17	7.12
1999	OH	Total Electric Industry	8.68	7.67	4.33	NA	5.97	6.40
2000	IL	Total Electric Industry	8.83	7.31	4.99	NA	5.63	6.94
2000	IN	Total Electric Industry	6.87	5.93	3.81	NA	9.37	5.18
2000	KY	Total Electric Industry	5.47	5.14	3.01	NA	4.40	4.18
2000	MI	Total Electric Industry	8.52	7.90	5.09	NA	10.77	7.11
2000	OH	Total Electric Industry	8.61	7.61	4.37	NA	6.10	6.41
2001	IL	Total Electric Industry	8.71	7.40	4.65	NA	6.37	6.90
2001	IN	Total Electric Industry	6.92	5.29	4.11	NA	9.06	5.30
2001	KY	Total Electric Industry	5.58	5.20	3.04	NA	4.53	4.24

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2001	MI	Total Electric Industry	8.26	7.54	5.08	NA	10.38	6.97
2001	OH	Total Electric Industry	8.37	8.46	4.27	NA	5.86	6.62
2002	IL	Total Electric Industry	8.39	7.52	4.89	NA	5.88	6.94
2002	IN	Total Electric Industry	6.91	5.98	3.95	NA	9.75	5.34
2002	KY	Total Electric Industry	5.65	5.30	3.09	NA	4.61	4.26
2002	MI	Total Electric Industry	8.28	7.79	5.02	NA	10.43	7.09
2002	OH	Total Electric Industry	8.24	7.81	4.87	NA	5.42	6.77
2003	IL	Total Electric Industry	8.38	7.30	4.86	5.87	NA	6.86
2003	IN	Total Electric Industry	7.04	6.12	3.92	8.36	NA	5.37
2003	KY	Total Electric Industry	5.81	5.37	3.21	0.00	NA	4.42
2003	MI	Total Electric Industry	8.35	7.55	4.96	8.21	NA	6.85
2003	OH	Total Electric Industry	8.26	7.55	4.79	6.17	NA	6.73
2004	IL	Total Electric Industry	8.37	7.54	4.65	5.70	NA	6.80
2004	IN	Total Electric Industry	7.30	6.31	4.13	8.76	NA	5.58
2004	KY	Total Electric Industry	6.11	5.60	3.34	0.00	NA	4.63
2004	MI	Total Electric Industry	8.33	7.57	4.92	7.89	NA	6.94
2004	OH	Total Electric Industry	8.45	7.75	4.89	9.21	NA	6.89
2005	IL	Total Electric Industry	8.34	7.75	4.61	5.61	NA	6.95
2005	IN	Total Electric Industry	7.50	6.57	4.42	9.14	NA	5.88
2005	KY	Total Electric Industry	6.57	6.01	3.60	0.00	NA	5.01
2005	MI	Total Electric Industry	8.40	7.84	5.32	13.07	NA	7.23
2005	OH	Total Electric Industry	8.51	7.93	5.10	9.03	NA	7.08
2006	IL	Total Electric Industry	8.42	7.95	4.69	5.59	NA	7.07

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2006	IN	Total Electric Industry	8.22	7.21	4.95	9.66	NA	6.46
2006	KY	Total Electric Industry	7.02	6.44	4.05	0.00	NA	5.43
2006	MI	Total Electric Industry	9.77	8.51	6.05	10.06	NA	8.14
2006	OH	Total Electric Industry	9.34	8.44	5.61	10.13	NA	7.71
2007	IL	Total Electric Industry	10.12	8.57	6.61	6.43	NA	8.46
2007	IN	Total Electric Industry	8.26	7.29	4.89	10.09	NA	6.50
2007	KY	Total Electric Industry	7.34	6.76	4.47	0.00	NA	5.84
2007	MI	Total Electric Industry	10.21	8.77	6.47	9.76	NA	8.53
2007	OH	Total Electric Industry	9.57	8.67	5.76	9.98	NA	7.91
2008	IL	Total Electric Industry	11.07	11.79	4.54	7.23	NA	9.26
2008	IN	Total Electric Industry	8.87	7.82	5.46	9.60	NA	7.09
2008	KY	Total Electric Industry	7.94	7.29	4.82	0.00	NA	6.26
2008	MI	Total Electric Industry	10.75	9.20	6.74	11.83	NA	8.94
2008	OH	Total Electric Industry	10.06	9.22	6.19	10.68	NA	8.39
2009	IL	Total Electric Industry	11.27	8.99	6.84	8.32	NA	9.08
2009	IN	Total Electric Industry	9.50	8.32	5.81	9.65	NA	7.62
2009	KY	Total Electric Industry	8.37	7.63	4.91	0.00	NA	6.52
2009	MI	Total Electric Industry	11.60	9.24	6.99	10.79	NA	9.40
2009	OH	Total Electric Industry	10.67	9.65	6.71	10.73	NA	9.01
2010	IL	Total Electric Industry	11.52	8.88	6.82	6.71	NA	9.13
2010	IN	Total Electric Industry	9.56	8.38	5.87	9.21	NA	7.67
2010	KY	Total Electric Industry	8.57	7.88	5.05	0.00	NA	6.73
2010	MI	Total Electric Industry	12.46	9.81	7.08	10.65	NA	9.88

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2010	OH	Total Electric Industry	11.32	9.73	6.40	8.62	NA	9.14
2011	IL	Total Electric Industry	11.78	8.64	6.42	6.81	NA	8.97
2011	IN	Total Electric Industry	10.06	8.77	6.17	9.74	NA	8.01
2011	KY	Total Electric Industry	9.20	8.49	5.33	0.00	NA	7.17
2011	MI	Total Electric Industry	13.27	10.33	7.32	8.53	NA	10.40
2011	OH	Total Electric Industry	11.42	9.63	6.12	6.64	NA	9.03
2012	IL	Total Electric Industry	11.38	7.99	5.80	6.15	NA	8.40
2012	IN	Total Electric Industry	10.53	9.14	6.34	9.56	NA	8.29
2012	KY	Total Electric Industry	9.43	8.73	5.35	0.00	NA	7.26
2012	MI	Total Electric Industry	14.13	10.93	7.62	8.08	NA	10.98
2012	OH	Total Electric Industry	11.76	9.47	6.24	6.98	NA	9.12

Source: U.S. Energy Information Administration "1990-2012 Average Price by State by Provider"
***available at* http://www.eia.gov/electricity/data/state/.**

Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2013 and 2012 (Cents per Kilowatthour)

Census Division and State	Residential December 2013 YTD	Residential December 2012 YTD	Commercial December 2013 YTD	Commercial December 2012 YTD	Industrial December 2013 YTD	Industrial December 2012 YTD	Transportation December 2013 YTD	Transportation December 2012 YTD	All Sectors December 2013 YTD	All Sectors December 2012 YTD
New England	16.20	15.71	14.08	13.88	12.17	11.83	9.17	6.88	14.48	14.02
Connecticut	17.58	17.34	14.84	14.65	12.68	12.67	10.31	9.69	15.68	15.54
Maine	14.35	14.66	11.72	11.53	8.32	7.98	–	–	11.87	11.81
Massachusetts	15.73	14.91	14.51	13.84	13.09	12.57	NM	4.91	14.51	13.79
New Hampshire	16.36	16.07	13.52	13.36	11.41	11.83	–	–	14.31	14.19
Rhode Island	15.47	14.40	13.08	11.87	11.87	10.88	13.00	8.28	13.91	12.74
Vermont	17.15	17.01	14.84	14.32	10.19	9.98	–	–	14.46	14.22
Middle Atlantic	15.72	15.27	13.00	12.97	7.25	7.49	12.17	12.50	12.90	12.75
New Jersey	15.72	15.78	12.80	12.78	10.71	10.52	10.43	9.77	13.70	13.68
New York	18.84	17.62	15.23	15.06	6.29	6.70	13.63	14.20	15.62	15.15
Pennsylvania	12.82	12.75	9.26	9.44	7.00	7.23	7.82	8.07	9.83	9.91
East North Central	12.01	12.05	9.51	9.48	6.57	6.51	5.71	6.33	9.33	9.27
Illinois	10.25	11.37	7.88	7.99	5.73	5.80	5.44	6.15	7.99	8.40
Indiana	10.54	10.53	9.45	9.14	6.69	6.34	8.67	9.56	8.63	8.29
Michigan	14.59	14.13	11.07	10.93	7.78	7.62	9.92	8.08	11.26	10.98
Ohio	11.91	11.76	9.38	9.47	6.10	6.24	6.61	6.98	9.16	9.12
Wisconsin	13.70	13.19	10.84	10.51	7.54	7.34	–	–	10.64	10.28
West North Central	10.95	10.59	8.95	8.48	6.60	6.28	8.78	7.72	8.98	8.54
Iowa	11.15	10.82	8.47	8.01	5.66	5.30	–	–	8.12	7.71
Kansas	11.56	11.24	9.54	9.24	7.07	7.09	–	–	9.57	9.33
Minnesota	11.94	11.35	9.53	8.84	7.06	6.54	9.79	8.67	9.52	8.86
Missouri	10.52	10.17	8.72	8.20	6.14	5.89	7.90	6.97	8.96	8.53
Nebraska	10.31	10.04	8.62	8.38	7.22	7.01	–	–	8.69	8.37
North Dakota	9.10	9.06	8.31	8.02	7.20	6.55	–	–	8.19	7.83
South Dakota	10.26	10.07	8.44	8.10	6.93	6.57	–	–	8.83	8.49
South Atlantic	11.37	11.38	9.39	9.37	6.48	6.55	8.66	8.44	9.73	9.73
Delaware	13.01	13.58	10.28	10.13	8.50	8.36	–	–	10.98	11.06
District of Columbia	12.56	12.28	11.93	12.02	5.89	5.46	9.58	9.01	11.85	11.85
Florida	11.36	11.42	9.49	9.66	7.68	8.04	8.69	8.45	10.30	10.44
Georgia	11.24	11.17	9.84	9.58	6.11	5.98	8.03	7.65	9.53	9.37
Maryland	13.24	12.84	10.70	10.43	8.36	8.09	8.48	8.29	11.65	11.28
North Carolina	10.91	10.91	8.73	8.66	6.34	6.42	7.94	7.88	9.18	9.15
South Carolina	11.82	11.77	9.82	9.63	5.92	6.02	–	–	9.14	9.10
Virginia	10.93	11.08	8.05	8.08	6.65	6.72	8.17	8.51	9.01	9.07
West Virginia	9.52	9.85	8.16	8.42	6.20	6.33	8.68	8.66	7.91	8.14
East South Central	10.42	10.32	9.82	9.87	5.98	6.11	11.46	11.28	8.71	8.58
Alabama	11.27	11.40	10.50	10.63	5.99	6.22	–	–	9.02	9.18
Kentucky	9.71	9.43	8.50	8.73	5.40	5.35	–	–	7.54	7.26
Mississippi	10.82	10.26	10.21	9.33	6.45	6.24	–	–	9.15	8.80
Tennessee	10.04	10.10	10.01	10.31	6.44	7.08	11.46	11.28	9.22	9.27
West South Central	10.73	10.30	8.11	7.99	5.86	5.39	10.02	10.30	8.47	8.11
Arkansas	9.51	9.30	7.98	7.71	5.88	5.76	NM	11.23	7.82	7.62
Louisiana	9.39	8.37	8.94	7.75	5.89	4.76	9.45	8.72	8.00	6.90
Oklahoma	9.62	9.51	7.71	7.32	5.34	5.09	–	–	7.81	7.54
Texas	11.37	10.98	8.03	8.16	5.93	5.57	10.12	10.54	8.77	8.55
Mountain	11.32	10.94	9.37	8.99	6.46	6.18	10.47	9.62	9.18	8.82
Arizona	11.74	11.29	9.87	9.53	6.69	6.53	–	–	10.16	9.81
Colorado	11.87	11.46	9.87	9.39	7.22	6.95	10.55	9.69	9.80	9.39
Idaho	9.37	8.67	7.40	6.86	6.12	5.48	–	–	7.61	6.92
Montana	10.38	10.08	9.52	9.13	5.37	5.10	–	–	8.58	8.25
Nevada	11.89	11.83	9.02	8.83	6.52	6.48	8.47	8.40	9.04	8.95
New Mexico	11.69	11.37	9.78	9.32	6.32	5.83	–	–	9.24	8.83
Utah	10.42	9.93	8.37	8.06	5.88	5.62	10.68	9.79	8.18	7.84
Wyoming	10.16	9.85	8.60	8.24	6.41	6.03	–	–	7.55	7.19
Pacific Contiguous	13.80	12.94	12.77	11.92	8.20	7.78	7.72	7.21	12.07	11.38
California	16.39	15.34	14.57	13.41	11.17	10.49	7.68	7.17	14.57	13.53
Oregon	9.94	9.80	8.39	8.31	5.86	5.59	6.88	8.24	8.39	8.21
Washington	8.87	8.53	7.76	7.68	4.22	4.13	8.29	8.06	7.06	6.94
Pacific Noncontiguous	28.59	28.76	25.52	25.50	26.08	26.99	–	–	26.61	26.96
Alaska	18.19	17.88	15.62	14.83	15.77	16.82	–	–	16.52	16.33
Hawaii	36.99	37.34	34.06	34.88	29.87	30.82	–	–	33.27	34.04
U.S. Total	12.12	11.88	10.29	10.09	6.82	6.67	10.28	10.21	10.08	9.84

See Technical notes for additional information on the Commercial, Industrial, and Transportation sectors.

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values for 2012 are final. Values for 2013 are preliminary estimates based on a cutoff model sample.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.

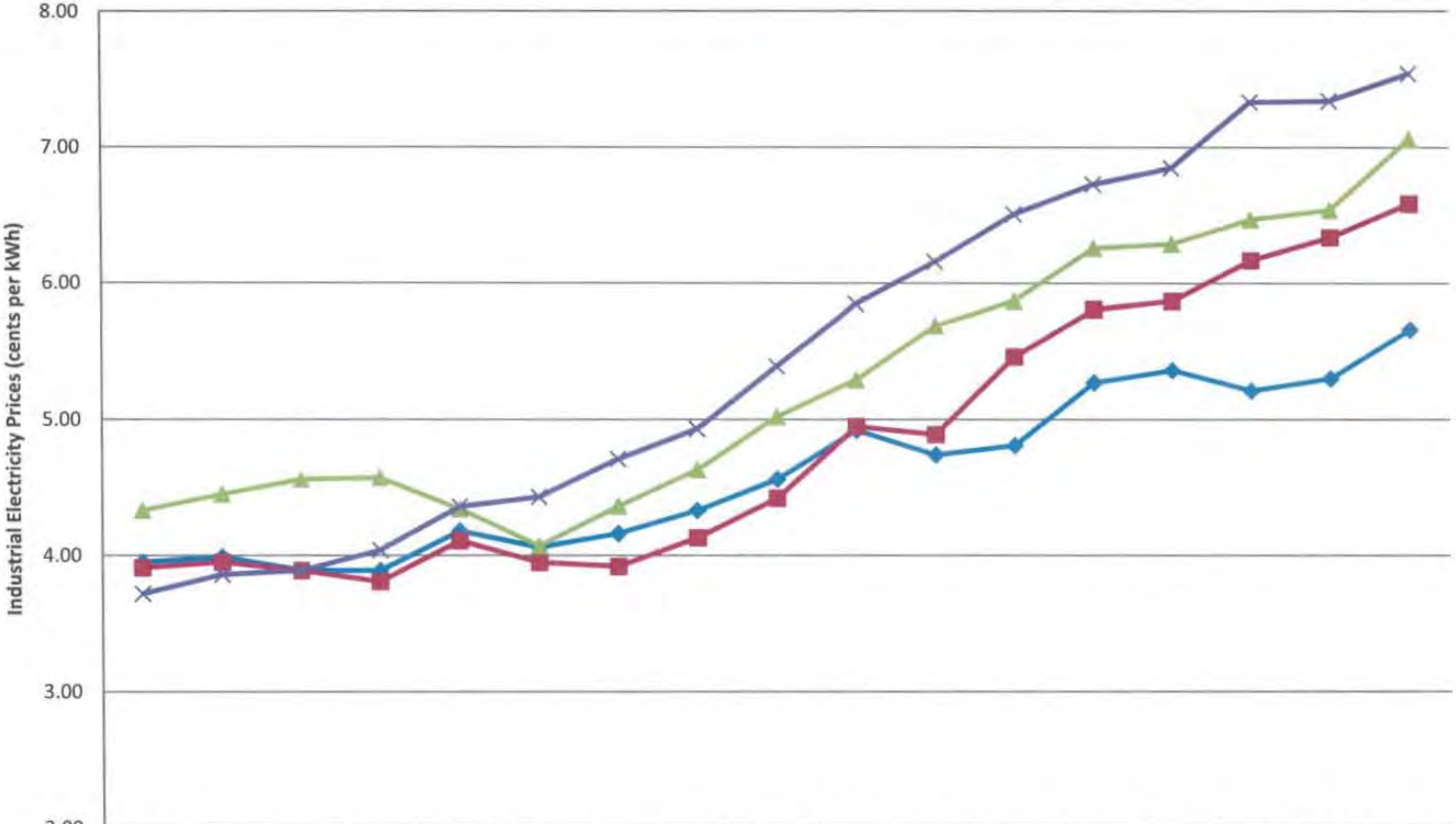
Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Electric Power Monthly, available at http://www.eia.gov/electricity/monthly/

Exhibit E

Industrial Electricity Prices of Indiana and Upper Midwest



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
IA	3.95	3.99	3.89	3.89	4.18	4.06	4.16	4.33	4.56	4.92	4.74	4.81	5.27	5.36	5.21	5.30	5.66
IN	3.91	3.95	3.89	3.81	4.11	3.95	3.92	4.13	4.42	4.95	4.89	5.46	5.81	5.87	6.17	6.34	6.59
MN	4.33	4.45	4.56	4.57	4.34	4.07	4.36	4.63	5.02	5.29	5.69	5.87	6.26	6.29	6.47	6.54	7.06
WI	3.72	3.86	3.89	4.04	4.36	4.43	4.71	4.93	5.39	5.85	6.16	6.51	6.73	6.85	7.33	7.34	7.54

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
1997	IA	Total Electric Industry	8.21	6.61	3.95	NA	6.09	5.97
1997	IN	Total Electric Industry	6.94	6.04	3.91	NA	9.44	5.29
1997	MN	Total Electric Industry	7.23	6.23	4.33	NA	7.12	5.61
1997	WI	Total Electric Industry	6.88	5.60	3.72	NA	6.77	5.22
1998	IA	Total Electric Industry	8.38	6.67	3.99	NA	6.21	6.04
1998	IN	Total Electric Industry	7.01	6.08	3.95	NA	9.83	5.34
1998	MN	Total Electric Industry	7.33	6.28	4.45	NA	7.48	5.71
1998	WI	Total Electric Industry	7.17	5.87	3.86	NA	7.01	5.44
1999	IA	Total Electric Industry	8.35	6.45	3.89	NA	6.30	5.93
1999	IN	Total Electric Industry	6.96	6.05	3.89	NA	9.70	5.29
1999	MN	Total Electric Industry	7.41	6.31	4.56	NA	7.49	5.83
1999	WI	Total Electric Industry	7.31	5.88	3.89	NA	7.11	5.53
2000	IA	Total Electric Industry	8.37	6.57	3.89	NA	6.13	5.93
2000	IN	Total Electric Industry	6.87	5.93	3.81	NA	9.37	5.18
2000	MN	Total Electric Industry	7.52	6.36	4.57	NA	7.60	5.87
2000	WI	Total Electric Industry	7.53	6.03	4.04	NA	7.40	5.71
2001	IA	Total Electric Industry	8.41	6.69	4.18	NA	5.67	6.14
2001	IN	Total Electric Industry	6.92	5.29	4.11	NA	9.06	5.30
2001	MN	Total Electric Industry	7.61	6.03	4.34	NA	7.43	5.97
2001	WI	Total Electric Industry	7.90	6.34	4.36	NA	7.70	6.08
2002	IA	Total Electric Industry	8.35	6.56	4.06	NA	4.92	6.01
2002	IN	Total Electric Industry	6.91	5.98	3.95	NA	9.75	5.34
2002	MN	Total Electric Industry	7.49	5.88	4.07	NA	7.36	5.80
2002	WI	Total Electric Industry	8.18	6.54	4.43	NA	8.08	6.28
2003	IA	Total Electric Industry	8.57	6.24	4.16	0.00	NA	6.11
2003	IN	Total Electric Industry	7.04	6.12	3.92	8.36	NA	5.37
2003	MN	Total Electric Industry	7.65	6.12	4.36	0.00	NA	6.01
2003	WI	Total Electric Industry	8.67	6.97	4.71	0.00	NA	6.64

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2004	IA	Total Electric Industry	8.96	6.75	4.33	0.00	NA	6.40
2004	IN	Total Electric Industry	7.30	6.31	4.13	8.76	NA	5.58
2004	MN	Total Electric Industry	7.92	6.31	4.63	6.75	NA	6.24
2004	WI	Total Electric Industry	9.07	7.24	4.93	0.00	NA	6.88
2005	IA	Total Electric Industry	9.27	6.95	4.56	0.00	NA	6.69
2005	IN	Total Electric Industry	7.50	6.57	4.42	9.14	NA	5.88
2005	MN	Total Electric Industry	8.28	6.59	5.02	6.21	NA	6.61
2005	WI	Total Electric Industry	9.66	7.67	5.39	0.00	NA	7.48
2006	IA	Total Electric Industry	9.63	7.29	4.92	7.05	NA	7.01
2006	IN	Total Electric Industry	8.22	7.21	4.95	9.66	NA	6.46
2006	MN	Total Electric Industry	8.70	7.02	5.29	7.95	NA	6.98
2006	WI	Total Electric Industry	10.51	8.37	5.85	0.00	NA	8.13
2007	IA	Total Electric Industry	9.45	7.11	4.74	0.00	NA	6.83
2007	IN	Total Electric Industry	8.26	7.29	4.89	10.09	NA	6.50
2007	MN	Total Electric Industry	9.18	7.48	5.69	8.27	NA	7.44
2007	WI	Total Electric Industry	10.87	8.71	6.16	0.00	NA	8.48
2008	IA	Total Electric Industry	9.49	7.18	4.81	0.00	NA	6.89
2008	IN	Total Electric Industry	8.87	7.82	5.46	9.60	NA	7.09
2008	MN	Total Electric Industry	9.74	7.88	5.87	8.04	NA	7.79
2008	WI	Total Electric Industry	11.51	9.28	6.51	0.00	NA	9.00
2009	IA	Total Electric Industry	9.99	7.55	5.27	0.00	NA	7.37
2009	IN	Total Electric Industry	9.50	8.32	5.81	9.65	NA	7.62
2009	MN	Total Electric Industry	10.04	7.92	6.26	7.73	NA	8.14
2009	WI	Total Electric Industry	11.94	9.57	6.73	0.00	NA	9.38
2010	IA	Total Electric Industry	10.42	7.91	5.36	0.00	NA	7.66
2010	IN	Total Electric Industry	9.56	8.38	5.87	9.21	NA	7.67
2010	MN	Total Electric Industry	10.59	8.38	6.29	7.77	NA	8.41
2010	WI	Total Electric Industry	12.65	9.98	6.85	0.00	NA	9.78

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012

Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2011	IA	Total Electric Industry	10.46	7.85	5.21	0.00	NA	7.56
2011	IN	Total Electric Industry	10.06	8.77	6.17	9.74	NA	8.01
2011	MN	Total Electric Industry	10.96	8.63	6.47	8.23	NA	8.65
2011	WI	Total Electric Industry	13.02	10.42	7.33	0.00	NA	10.21
2012	IA	Total Electric Industry	10.82	8.01	5.30	0.00	NA	7.71
2012	IN	Total Electric Industry	10.53	9.14	6.34	9.56	NA	8.29
2012	MN	Total Electric Industry	11.35	8.84	6.54	8.67	NA	8.86
2012	WI	Total Electric Industry	13.19	10.51	7.34	0.00	NA	10.28

Source: U.S. Energy Information Administration "1990-2012 Average Price by State by Provider"
available at **http://www.eia.gov/electricity/data/state/.**

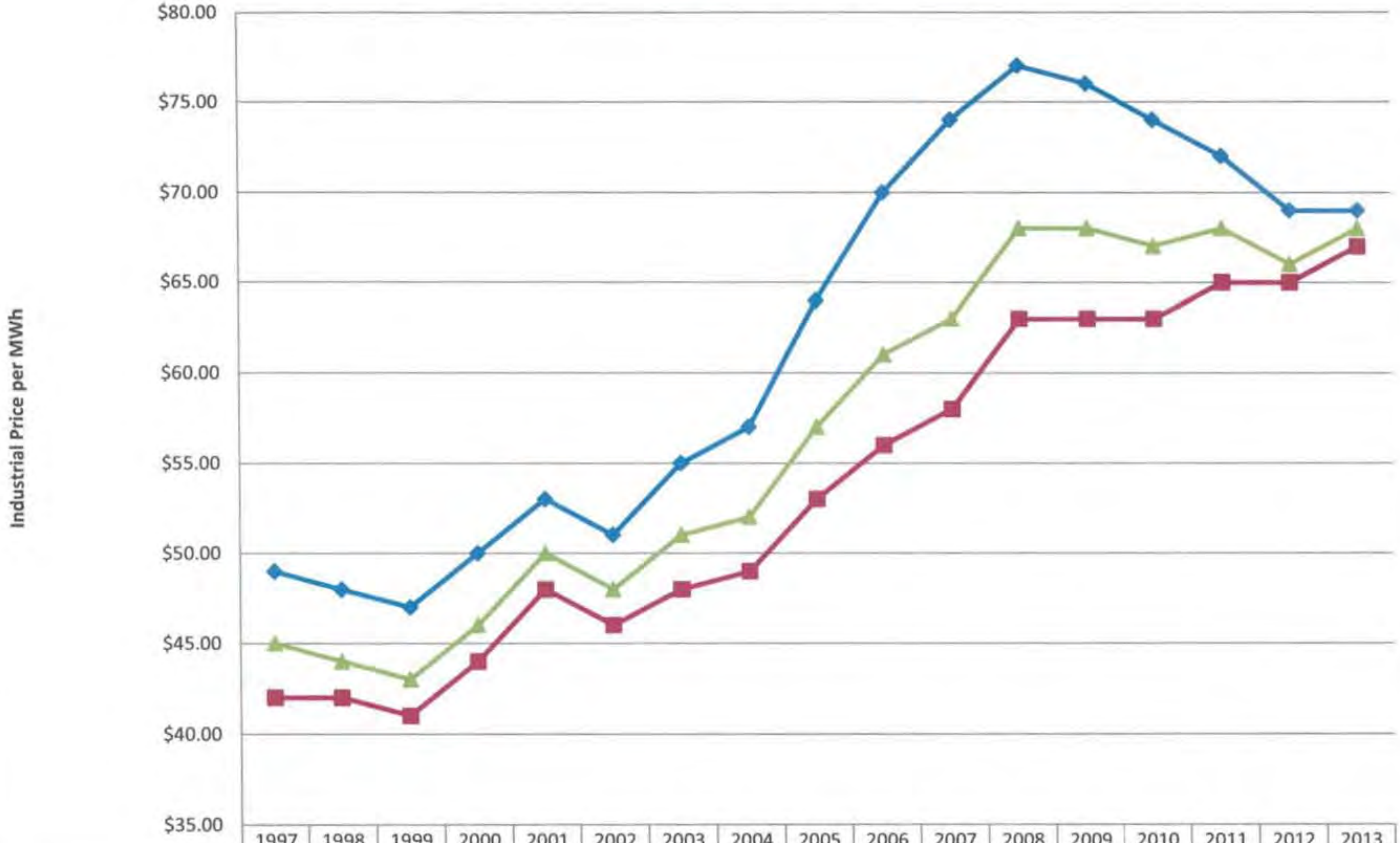
Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2013 and 2012 (Cents per Kilowatthour)

Census Division and State	Residential		Commercial		Industrial		Transportation		All Sectors	
	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD	December 2013 YTD	December 2012 YTD
New England	16.20	15.71	14.08	13.68	12.17	11.83	9.17	6.68	14.48	14.02
Connecticut	17.58	17.34	14.64	14.65	12.68	12.67	10.31	9.69	15.68	15.54
Maine	14.35	14.66	11.72	11.53	8.32	7.98	–	–	11.87	11.81
Massachusetts	15.73	14.91	14.51	13.84	13.09	12.57	NM	4.91	14.51	13.79
New Hampshire	16.36	16.07	13.52	13.36	11.41	11.83	–	–	14.31	14.19
Rhode Island	15.47	14.40	13.08	11.87	11.87	10.68	13.00	8.28	13.91	12.74
Vermont	17.15	17.01	14.64	14.32	10.19	9.98	–	–	14.46	14.22
Middle Atlantic	15.72	15.27	13.00	12.97	7.25	7.49	12.17	12.50	12.90	12.75
New Jersey	15.72	15.78	12.80	12.78	10.71	10.52	10.43	9.77	13.70	13.68
New York	18.84	17.62	15.23	15.06	6.29	6.70	13.63	14.20	15.62	15.15
Pennsylvania	12.82	12.75	9.26	9.44	7.00	7.23	7.82	8.07	9.83	9.91
East North Central	12.01	12.05	9.51	9.46	6.57	6.51	5.71	6.33	9.33	9.27
Illinois	10.25	11.37	7.88	7.99	5.73	5.80	5.44	6.15	7.99	8.40
Indiana	10.84	10.53	9.48	9.14	6.59	6.34	9.87	9.58	8.63	8.29
Michigan	14.59	14.13	11.07	10.93	7.78	7.62	9.92	8.08	11.26	10.98
Ohio	11.91	11.76	9.38	9.47	6.10	6.24	6.61	6.98	9.16	9.12
Wisconsin	13.70	13.19	10.84	10.51	7.54	7.34	–	–	10.64	10.28
West North Central	10.95	10.59	8.95	8.48	6.60	6.28	8.78	7.72	8.96	8.54
Iowa	11.15	10.82	8.47	8.01	5.66	5.30	–	–	8.12	7.71
Kansas	11.56	11.24	9.54	9.24	7.07	7.09	–	–	9.57	9.33
Minnesota	11.94	11.35	9.53	8.84	7.06	6.54	9.79	8.67	9.52	8.86
Missouri	10.52	10.17	8.72	8.20	6.14	5.89	7.90	6.97	8.96	8.53
Nebraska	10.31	10.04	8.62	8.38	7.22	7.01	–	–	8.69	8.37
North Dakota	9.10	9.06	8.31	8.02	7.20	6.55	–	–	8.19	7.83
South Dakota	10.26	10.07	8.44	8.10	6.93	6.57	–	–	8.83	8.49
South Atlantic	11.37	11.38	9.39	9.37	6.48	6.55	8.66	8.44	9.73	9.73
Delaware	13.01	13.58	10.26	10.13	8.50	8.36	–	–	10.98	11.06
District of Columbia	12.56	12.28	11.93	12.02	5.89	5.46	9.58	9.01	11.85	11.85
Florida	11.36	11.42	9.49	9.66	7.68	8.04	8.69	8.45	10.30	10.44
Georgia	11.24	11.17	9.84	9.58	6.11	5.98	8.03	7.65	9.53	9.37
Maryland	13.24	12.84	10.70	10.43	8.36	8.09	8.48	8.29	11.65	11.28
North Carolina	10.91	10.91	8.73	8.66	6.34	6.42	7.94	7.88	9.18	9.15
South Carolina	11.82	11.77	9.82	9.63	5.92	6.02	–	–	9.14	9.10
Virginia	10.93	11.08	8.05	8.08	6.65	6.72	8.17	8.51	9.01	9.07
West Virginia	9.52	9.85	8.16	8.42	6.20	6.33	8.68	8.66	7.91	8.14
East South Central	10.42	10.32	9.82	9.87	5.96	6.11	11.46	11.28	8.71	8.58
Alabama	11.27	11.40	10.50	10.63	5.99	6.22	–	–	9.02	9.18
Kentucky	9.71	9.43	8.50	8.73	5.40	5.35	–	–	7.54	7.26
Mississippi	10.82	10.26	10.21	9.33	6.45	6.24	–	–	9.15	8.60
Tennessee	10.04	10.10	10.01	10.31	6.44	7.08	11.46	11.28	9.22	9.27
West South Central	10.73	10.30	8.11	7.99	5.86	5.39	10.02	10.30	8.47	8.11
Arkansas	9.51	9.30	7.98	7.71	5.88	5.76	NM	11.23	7.82	7.62
Louisiana	9.39	8.37	8.94	7.75	5.89	4.76	9.45	8.72	8.00	6.90
Oklahoma	9.62	9.51	7.71	7.32	5.34	5.09	–	–	7.81	7.54
Texas	11.37	10.98	8.03	8.16	5.93	5.57	10.12	10.54	8.77	8.55
Mountain	11.32	10.94	9.37	8.99	6.46	6.18	10.47	9.62	9.18	8.82
Arizona	11.74	11.29	9.87	9.53	6.69	6.53	–	–	10.16	9.81
Colorado	11.87	11.46	9.87	9.39	7.22	6.95	10.55	9.69	9.80	9.39
Idaho	9.37	8.67	7.40	6.86	6.12	5.48	–	–	7.61	6.92
Montana	10.38	10.08	9.52	9.13	5.37	5.10	–	–	8.58	8.25
Nevada	11.89	11.83	9.02	8.83	6.52	6.48	8.47	8.40	9.04	8.95
New Mexico	11.69	11.37	9.78	9.32	6.32	5.83	–	–	9.24	8.83
Utah	10.42	9.93	8.37	8.06	5.88	5.62	10.68	9.79	8.18	7.84
Wyoming	10.18	9.85	8.60	8.24	6.41	6.03	–	–	7.55	7.19
Pacific Contiguous	13.60	12.94	12.77	11.92	8.20	7.78	7.72	7.21	12.07	11.38
California	16.39	15.34	14.57	13.41	11.17	10.49	7.68	7.17	14.57	13.53
Oregon	9.94	9.80	8.39	8.31	5.86	5.59	8.88	8.24	8.39	8.21
Washington	8.67	8.53	7.76	7.68	4.22	4.13	8.29	8.06	7.06	6.94
Pacific Noncontiguous	28.59	28.76	25.52	25.50	26.08	26.99	–	–	26.61	26.96
Alaska	18.19	17.88	15.62	14.93	15.77	16.82	–	–	16.52	16.33
Hawaii	36.99	37.34	34.06	34.88	29.87	30.82	–	–	33.27	34.04
U.S. Total	12.12	11.88	10.29	10.09	6.82	6.67	10.28	10.21	10.08	9.84

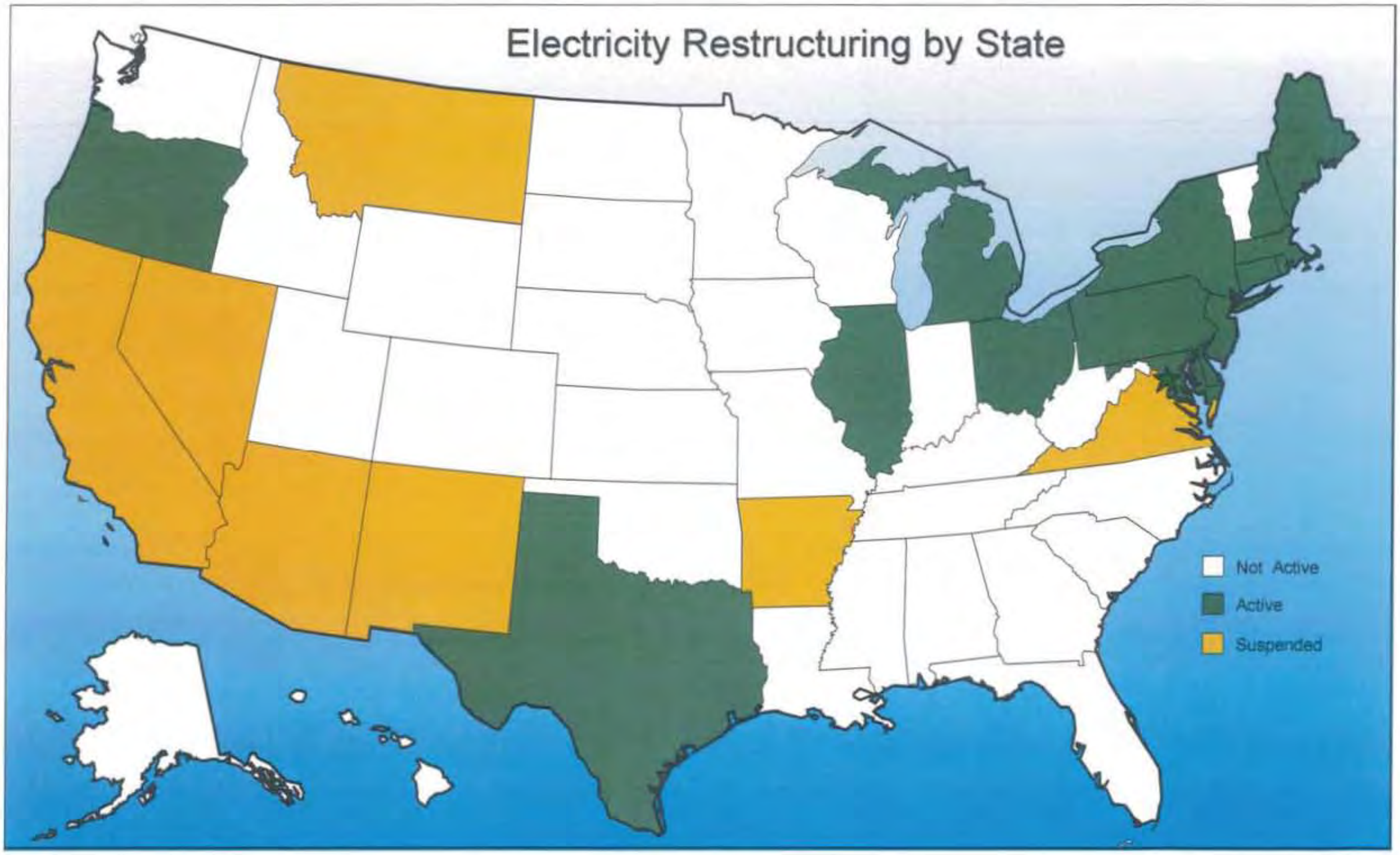
Source: U.S. Energy Information Administration, Electric Power Monthly, February 2014 available at http://www.eia.gov/electricity/monthly/

Exhibit F

Industrial Electricity Prices in Restructured and Regulated Markets



	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Restructured States	$49.00	$48.00	$47.00	$50.00	$53.00	$51.00	$55.00	$57.00	$64.00	$70.00	$74.00	$77.00	$76.00	$74.00	$72.00	$69.00	$69.00
Regulated States	$42.00	$42.00	$41.00	$44.00	$48.00	$46.00	$48.00	$49.00	$53.00	$56.00	$58.00	$63.00	$63.00	$63.00	$65.00	$65.00	$67.00
US Total	$45.00	$44.00	$43.00	$46.00	$50.00	$48.00	$51.00	$52.00	$57.00	$61.00	$63.00	$68.00	$68.00	$67.00	$68.00	$66.00	$68.00



Source: U.S. Energy Information Administration
Available at: http://www.eia.gov/electricity/policies/restructuring/index.html

List of Restructured States:

Connecticut
Delaware
District of Columbia
Illinois
Maine
Maryland
Massachusetts
Michigan
New Hampshire
New Jersey
New York
Ohio
Oregon
Pennsylvania
Rhode Island
Texas

Revenue from Industrial Sales of Electricity			
2013	Restructured	$	22,775,000,000.00
2013	State Regulation	$	42,335,000,000.00
2013	US	$	65,111,000,000.00
2012	Restructured	$	23,279,946,000.00
2012	State Regulation	$	42,481,315,000.00
2012	US	$	65,761,258,000.00
2011	Restructured	$	25,366,651,000.00
2011	State Regulation	$	42,239,101,000.00
2011	US	$	67,605,748,000.00
2010	Restructured	$	25,580,460,000.00
2010	State Regulation	$	40,170,034,000.00
2010	US	$	65,750,488,000.00
2009	Restructured	$	24,942,035,000.00
2009	State Regulation	$	37,561,796,000.00
2009	US	$	62,503,831,000.00
2008	Restructured	$	27,637,981,000.00
2008	State Regulation	$	41,282,407,000.00
2008	US	$	68,920,389,000.00
2007	Restructured	$	27,582,491,000.00
2007	State Regulation	$	38,129,448,000.00
2007	US	$	65,711,939,000.00
2006	Restructured	$	25,214,575,000.00
2006	State Regulation	$	37,093,133,000.00
2006	US	$	62,307,708,000.00
2005	Restructured	$	24,128,944,000.00
2005	State Regulation	$	34,316,338,000.00
2005	US	$	58,445,282,000.00
2004	Restructured	$	21,868,981,000.00
2004	State Regulation	$	31,608,081,000.00
2004	US	$	53,477,062,000.00
2003	Restructured	$	21,632,322,000.00
2003	State Regulation	$	30,108,608,000.00
2003	US	$	51,740,930,000.00
2002	Restructured	$	19,590,246,000.00
2002	State Regulation	$	28,745,611,000.00
2002	US	$	48,335,857,000.00
2001	Restructured	$	20,003,566,000.00
2001	State Regulation	$	30,289,372,000.00
2001	US	$	50,292,938,000.00
2000	Restructured	$	19,737,811,000.00
2000	State Regulation	$	29,631,678,000.00
2000	US	$	49,369,488,000.00
1999	Restructured	$	18,445,111,000.00
1999	State Regulation	$	36,253,315,000.00
1999	US	$	46,846,124,000.00
1998	Restructured	$	19,326,088,000.00
1998	State Regulation	$	27,723,783,000.00
1998	US	$	47,049,872,000.00
1997	Restructured	$	19,558,647,000.00
1997	State Regulation	$	27,464,848,000.00
1997	US	$	47,023,495,000.00

Source: US. Energy Information Administration
"1990-2012 Revenue from Retail Sales of Electricity
by Sector by Provider" available at
Available at http://www.eia.gov/electricity/data/state/
2013 data: Electric Power Monthly, Table 5.5B (Feb. 2014)
Available at http://www.eia.gov/electricity/monthly

Industrial Retail Sales of Electricity (MWh)		
2013	Restructured	329,350,000.00
2013	State Regulation	625,373,000.00
2013	US	954,725,000.00
2012	Restructured	340,391,273.00
2012	State Regulation	645,322,581.00
2012	US	985,713,854.00
2011	Restructured	349,837,342.00
2011	State Regulation	641,478,222.00
2011	US	991,315,564.00
2010	Restructured	341,589,153.00
2010	State Regulation	629,283,721.00
2010	US	970,872,874.00
2009	Restructured	326,748,321.00
2009	State Regulation	590,693,742.00
2009	US	917,442,063.00
2008	Restructured	357,688,353.00
2008	State Regulation	651,611,956.00
2008	US	1,009,300,309.00
2007	Restructured	370,585,874.00
2007	State Regulation	657,246,051.00
2007	US	1,027,831,925.00
2006	Restructured	357,833,591.00
2006	State Regulation	653,463,975.00
2006	US	1,011,297,566.00
2005	Restructured	376,498,466.00
2005	State Regulation	642,657,599.00
2005	US	1,019,156,065.00
2004	Restructured	381,108,829.00
2004	State Regulation	636,740,703.00
2004	US	1,017,849,532.00
2003	Restructured	392,743,573.00
2003	State Regulation	619,629,674.00
2003	US	1,012,373,247.00
2002	Restructured	377,425,329.00
2002	State Regulation	612,812,302.00
2002	US	990,237,631.00
2001	Restructured	374,930,816.00
2001	State Regulation	621,678,494.00
2001	US	996,609,310.00
2000	Restructured	392,091,351.00
2000	State Regulation	672,148,042.00
2000	US	1,064,239,393.00
1999	Restructured	390,364,750.00
1999	State Regulation	667,851,858.00
1999	US	1,058,216,608.00
1998	Restructured	369,011,781.00
1998	State Regulation	655,191,334.00
1998	US	1,051,203,115.00
1997	Restructured	395,094,206.00
1997	State Regulation	643,102,686.00
1997	US	1,038,196,892.00

Source: US. Energy Information Administration
"1990-2012 Retail Sales of Electricity
by State by Sector" available at
http://www.eia.gov/electricity/data/state/
2013 data: Electric Power Monthly, Table 5.4B (Feb. 2014)
Available at http://www.eia.gov/electricity/monthly

Price (Revenue/Sales)				
2013	Restructured	$ 22,775,000,000.00	329,350,000.00	$ 69.00
2013	State Regulation	$ 42,335,000,000.00	625,373,000.00	$ 67.00
2013	US	$ 65,111,000,000.00	954,725,000.00	$ 68.00
2012	Restructured	$ 23,279,946,000.00	340,391,273.00	$ 68.00
2012	State Regulation	$ 42,481,315,000.00	645,322,581.00	$ 65.00
2012	US	$ 65,761,258,000.00	985,713,854.00	$ 66.00
2011	Restructured	$ 25,366,651,000.00	349,837,342.00	$ 72.00
2011	State Regulation	$ 42,239,101,000.00	641,478,222.00	$ 65.00
2011	US	$ 67,605,748,000.00	991,315,564.00	$ 68.00
2010	Restructured	$ 25,580,460,000.00	341,589,153.00	$ 74.00
2010	State Regulation	$ 40,170,034,000.00	629,283,721.00	$ 63.00
2010	US	$ 65,750,488,000.00	970,872,874.00	$ 67.00
2009	Restructured	$ 24,942,035,000.00	326,748,321.00	$ 76.00
2009	State Regulation	$ 37,561,796,000.00	590,693,742.00	$ 63.00
2009	US	$ 62,503,831,000.00	917,442,063.00	$ 68.00
2008	Restructured	$ 27,637,981,000.00	357,688,353.00	$ 77.00
2008	State Regulation	$ 41,282,407,000.00	651,611,956.00	$ 63.00
2008	US	$ 68,920,389,000.00	1,009,300,309.00	$ 68.00
2007	Restructured	$ 27,582,491,000.00	370,585,874.00	$ 74.00
2007	State Regulation	$ 38,129,448,000.00	657,246,051.00	$ 58.00
2007	US	$ 65,711,939,000.00	1,027,831,925.00	$ 63.00
2006	Restructured	$ 25,214,575,000.00	357,833,591.00	$ 70.00
2006	State Regulation	$ 37,093,133,000.00	653,463,975.00	$ 56.00
2006	US	$ 62,307,708,000.00	1,011,297,566.00	$ 61.00
2005	Restructured	$ 24,128,944,000.00	376,498,466.00	$ 64.00
2005	State Regulation	$ 34,316,338,000.00	642,657,599.00	$ 53.00
2005	US	$ 58,445,282,000.00	1,019,156,065.00	$ 57.00
2004	Restructured	$ 21,868,981,000.00	381,108,829.00	$ 57.00
2004	State Regulation	$ 31,608,081,000.00	636,740,703.00	$ 49.00
2004	US	$ 53,477,062,000.00	1,017,849,532.00	$ 52.00
2003	Restructured	$ 21,632,322,000.00	392,743,573.00	$ 55.00
2003	State Regulation	$ 30,108,608,000.00	619,629,674.00	$ 48.00
2003	US	$ 51,740,930,000.00	1,012,373,247.00	$ 51.00
2002	Restructured	$ 19,590,246,000.00	377,425,329.00	$ 51.00
2002	State Regulation	$ 28,745,611,000.00	612,812,302.00	$ 46.00
2002	US	$ 48,335,857,000.00	990,237,631.00	$ 48.00
2001	Restructured	$ 20,003,566,000.00	374,930,816.00	$ 53.00
2001	State Regulation	$ 30,289,372,000.00	621,678,494.00	$ 48.00
2001	US	$ 50,292,938,000.00	996,609,310.00	$ 50.00
2000	Restructured	$ 19,737,811,000.00	392,091,351.00	$ 50.00
2000	State Regulation	$ 29,631,678,000.00	672,148,042.00	$ 44.00
2000	US	$ 49,369,488,000.00	1,064,239,393.00	$ 46.00
1999	Restructured	390,364,750.00	$ 18,445,111,000.00	$ 47.00
1999	State Regulation	$ 36,253,315,000.00	667,851,858.00	$ 54.00
1999	US	$ 46,846,124,000.00	1,058,216,608.00	$ 44.00
1998	Restructured	$ 19,326,088,000.00	369,011,781.00	$ 48.00
1998	State Regulation	$ 27,723,783,000.00	655,191,334.00	$ 42.00
1998	US	$ 47,049,872,000.00	1,051,203,115.00	$ 44.00
1997	Restructured	$ 19,558,647,000.00	395,094,206.00	$ 49.00
1997	State Regulation	$ 27,464,848,000.00	643,102,686.00	$ 42.00
1997	US	$ 47,023,495,000.00	1,038,196,892.00	$ 45.00

Exhibit G

How Trackers Violate Accepted Ratemaking Practices

Indiana's capital expense trackers have two fundamental problems. A utility should not be allowed to recover costs associated with incremental capital investment in infrastructure improvements and ignore that rates are set using net depreciated plant. Increases in capital investment can be offset by reductions in net plant due to depreciation of existing plant. Second, cost recovery should not ignore the additional revenues that the utility will recover in its base rates resulting from load growth. Every additional kilowatt-hour that the utility sells will generate additional revenues. These additional revenues can offset higher costs.

Unless these problems are corrected, rates will not be just and reasonable. Utilities will collect excess revenues to the benefit of its shareholders. Retail customers will be overcharged.

These two problems are illustrated in the attached charts.

1. <u>Rates Are Set Using Net Depreciated Investment</u>

The starting point assumes that a utility has a $500 net investment before the implementation of a tracker (column 1). The $500 consists of $1,000 of gross plant less $500 of accumulated depreciation. For purposes of the illustration, we have assumed a 10% depreciation rate and the utility is allowed to earn a 10% rate of return (ROR) on net investment. This results in a rate case or baseline revenue requirement of $150.

Next, we show the impact of a tracker that recovers $200 of new capital investment 1 year after the rate case. When viewed in isolation, a $200 investment would require $40 of additional revenues (column 2). Thus, the utility would collect $190 ($150 + $40).

However, if the $200 is viewed together with the utility's other investment, we see that the utility's total cost would increase to only $180 (column 3). This is because the utility has experienced one additional year of depreciation on its other investments, and the $200 capital addition has also been depreciated. Thus, the utility requires only $30 of additional revenue, not $40 if the new capital investment is viewed in isolation. **Ignoring depreciation on the utility's other plant and the new capital addition, the utility will over-recover from its customers (by $10 in the example).**

2. <u>Load Growth Offsets New Investment</u>

Starting from Slide 1, we assume that the utility sells 30 MW of power and that to recover the $150 baseline revenue requirement, it must charge $5 ($150 ÷ 30 MW = $5). We assume the tracker is set to charge $30, which recognizes depreciation (column 1).

Subsequently, we then assume that the utility's sales grow to 36 MW. The additional sales generate $30 of additional revenue (column 2). The utility now collects $180 of base revenues and $36 of tracker revenues for a total of $216. However, the utility's costs are still $180 (assuming no additional depreciation). Thus, the utility will over-recover by $36 if load growth is ignored.

If load growth is recognized, the tracker can be reset to $0 because the base rates (that collect $180) are sufficient to recover the utility's total costs (also $180). No over-recovery occurs. **Ignoring load growth will allow the utility to over-recover from its customers (by $36 in the example).**

How Trackers Violate Accepted Ratemaking Practices

1. Rates Are Set Using Net Depreciated Investment

Cost	Baseline Costs (Before Tracker)	Tracker Recovers New Investment	Total Investment	Tracker Based on Net Incremental Investment
Gross Investment	**$1,000**	**$200**	**$1,200**	**$200**
Annual Depreciation Expense (10%)	$100	$20	$120	$20
Accumulated Depreciation	($500)	$0	($600)	($100)
Net Investment	**$500**	**$200**	**$600**	**$100**
10% Before Tax Return on Investment	$50	$20	$60	$10
Revenue Requirement	$150	**$40**	$180	**$30**
Revenue Requirement with Tracker		**$190**		**$180**

J. POLLOCK

How Trackers Violate Accepted Ratemaking Practices

2. Load Growth Offsets New Investment

Cost Item	Tracker Based on Net Incremental Investment	Ignore Load Growth	Recognize Load Growth
Billing Units (MW)	30	36	36
Base Rate (per MW)	$5.00	$5.00	$5.00
Base Revenues	$150	$180	$180
Tracker Revenues	$30	$36	$0
Total Revenues	$180	$216	$180
Total Costs	$180	$180	$180
Over / (Under) Recovery	**$0**	**$36**	**$0**

J.POLLOCK

Exhibit H

Duke Energy Indiana

Rate Cases			
Year of petition	Cause #	Year of petition	Cause #
1994	None	2004	None
1995	**4003**	2005	None
1996	None	2006	None
1997	None	2007	None
1998	None	2008	None
1999	None	2009	None
2000	None	2010	None
2001	None	2011	None
2002	**42359**	2012	None
2003	None	2013	None

Current Number of Trackers*: **9**

Number of Tracker Proceedings in 2013: **16**

*Includes Fuel Cost Adjustment Rider, IGCC Rider, Qualified Pollution Control Property Rider, Emission Allowance Rider, Demand Side Management/Energy Efficiency Rider, Credits to Remove Annual Amortization of Cinergy Merger Costs Rider, MISO Management Cost Rider, Summer Reliability Rider, and Clean Coal Operating Cost Rider.

Indiana Michigan Power

Rate Cases			
Year of petition	Cause #	Year of petition	Cause #
1994	None	2004	None
1995	None	2005	None
1996	None	2006	None
1997	None	**2007**	**43306**
1998	None	2008	None
1999	None	2009	None
2000	None	2010	None
2001	None	**2011**	**44075**
2002	None	2012	None
2003	None	2013	None

Current Number of Trackers*: **7 (petition for 8th tracker pending)**

Number of Tracker Proceedings in 2013: **7**

*Includes Fuel Cost Adjustment Rider, Clean Coal Technology Rider, Demand-Side Management/Energy Efficiency Rider, Environmental Compliance Cost Rider, Off-System Sales Margin Sharing Rider, PJM Cost Rider, Life Cycle Management Rider. Petition for Capacity Settlement Rider is pending.

Indianapolis Power & Light Co.

Rate Cases			
Year of petition	Cause #	Year of petition	Cause #
1994	**39938**	2004	None
1995	None	2005	None
1996	None	2006	None
1997	None	2007	None
1998	None	2008	None
1999	None	2009	None
2000	None	2010	None
2001	None	2011	None
2002	None	2012	None
2003	None	2013	None

Current Number of Trackers*: **3**

Number of Tracker Proceedings in 2013: **9**

*Includes Fuel Adjustment Cost Rider, Environmental Compliance Cost Rider, and Core and Core Plus Demand-Side Management Rider. IPL does not have an RTO tracker, but it has deferred almost $100 million since 2004 for later collection.

NIPSCO

Rate Cases			
Year of petition	Cause #	Year of petition	Cause #
1994	None	2004	None
1995	None	2005	None
1996	None	2006	None
1997	None	2007	None
1998	None	**2008****	**43526**
1999	None	2009	None
2000	None	**2010**	**43969**
2001	None	2011	None
2002	None	2012	None
2003	None	2013	None

** Rates never went into effect

Current Number of Trackers*: **8**

Number of Tracker Proceedings in 2013: **16**

*Includes Fuel Adjustment Rider, Regional Transmission Organization Rider, Environmental Cost Recovery Rider, Environmental Expense Recovery Rider, Resource Adequacy Rider, DSM Rider, Federally Mandated Cost Rider and TDSIC Rider.

Vectren (SIGECO)

Rate Cases			
Year of petition	Cause #	Year of petition	Cause #
1994	None	2004	None
1995	None	2005	None
1996	None	**2006**	**43111**
1997	None	2007	None
1998	None	2008	None
1999	None	**2009**	**43839**
2000	None	2010	None
2001	None	2011	None
2002	None	2012	None
2003	None	2013	None

Current Number of Trackers*: **4**

Number of Tracker Proceedings in 2013: **9**

*Includes Fuel Adjustment Cost Rider, Demand Side Management Rider, MISO Cost and Revenue Adjustment Rider, and Reliability Cost and Revenue Adjustment Rider.

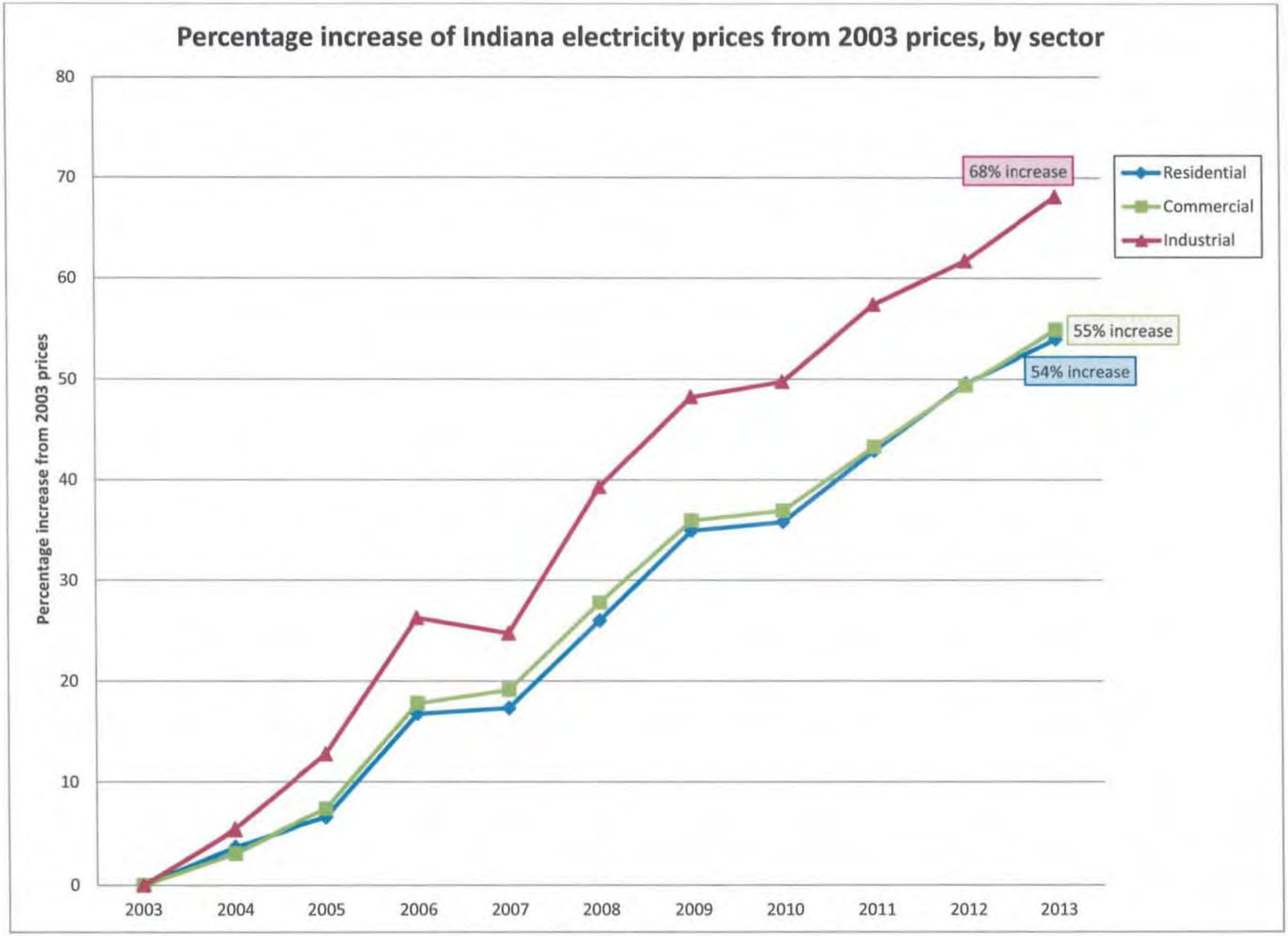
Exhibit I

Utility	Date of Order	ROE	Current ROE	National Average ROE 2013[1]	Excessive revenue recoverable in 2013 (in millions)
I&M	11/12/1993	12%			
Duke	2/17/1995	11.90%			
Vectren	7/21/1995	12.25%			
IPL	8/24/1995	12.10%[2]	12.10%	9.80%	$43.788
Duke	9/27/1996	11%			
Duke	5/18/2004	10.50%	10.50%	9.80%	$17.528
Vectren	8/15/2007	10.40%			
I&M	3/4/2009	10.50%			
Vectren	4/27/2011	10.40%	10.40%	9.80%	$5.198
NIPSCO	12/21/2011	10.20%	10.20%	9.80%	$7.748
I&M	2/13/2013	10.20%	10.20%	9.80%	$6.299
Total excessive revenues collectible from Indiana ratepayers in 2013 (in millions)					$80.561

[1] From Regulatory Research Associates, April 9, 2014.

[2] *See In re IPL*, Cause 43403 (IURC 04/02/08) at 13.

Exhibit J


Percentage increase of Indiana electricity prices from 2003 prices, by sector
Percentage increase from 2003 prices
0
10
20
30
40
50
60
70
80
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
68% increase
55% increase
54% increase
Residential
Commercial
Industrial

Taken from Average Price (Cents/kilowatthour) by State by Provider, 1990-2012								
Year	State	Industry Sector Category	Residential	Commercial	Industrial	Transportation	Other	Total
2012	IN	Total Electric Industry	10.53	9.14	6.34	9.56	NA	8.29
2011	IN	Total Electric Industry	10.06	8.77	6.17	9.74	NA	8.01
2010	IN	Total Electric Industry	9.56	8.38	5.87	9.21	NA	7.67
2009	IN	Total Electric Industry	9.50	8.32	5.81	9.65	NA	7.62
2008	IN	Total Electric Industry	8.87	7.82	5.46	9.60	NA	7.09
2007	IN	Total Electric Industry	8.26	7.29	4.89	10.09	NA	6.50
2006	IN	Total Electric Industry	8.22	7.21	4.95	9.66	NA	6.46
2005	IN	Total Electric Industry	7.50	6.57	4.42	9.14	NA	5.88
2004	IN	Total Electric Industry	7.30	6.31	4.13	8.76	NA	5.58
2003	IN	Total Electric Industry	7.04	6.12	3.92	8.36	NA	5.37
2002	IN	Total Electric Industry	6.91	5.98	3.95	NA	9.75	5.34
2001	IN	Total Electric Industry	6.92	5.29	4.11	NA	9.06	5.30
2000	IN	Total Electric Industry	6.87	5.93	3.81	NA	9.37	5.18
1999	IN	Total Electric Industry	6.96	6.05	3.89	NA	9.70	5.29
1998	IN	Total Electric Industry	7.01	6.08	3.95	NA	9.83	5.34
1997	IN	Total Electric Industry	6.94	6.04	3.91	NA	9.44	5.29

Source: U.S. Energy Information Administration "1990-2012 Average Price by State by Provider"
***available at* http://www.eia.gov/electricity/data/state/.**

Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through December 2013 and 2012 (Cents per Kilowatthour)

Census Division and State	Residential December 2013 YTD	Residential December 2012 YTD	Commercial December 2013 YTD	Commercial December 2012 YTD	Industrial December 2013 YTD	Industrial December 2012 YTD	Transportation December 2013 YTD	Transportation December 2012 YTD	All Sectors December 2013 YTD	All Sectors December 2012 YTD
New England	16.20	15.71	14.08	13.68	12.17	11.83	9.17	6.68	14.48	14.02
Connecticut	17.58	17.34	14.64	14.65	12.68	12.67	10.31	9.69	15.68	15.54
Maine	14.35	14.66	11.72	11.53	8.32	7.98	–	–	11.87	11.81
Massachusetts	15.73	14.91	14.51	13.84	13.09	12.57	NM	4.91	14.51	13.79
New Hampshire	16.36	16.07	13.52	13.36	11.41	11.83	–	–	14.31	14.19
Rhode Island	15.47	14.40	13.08	11.87	11.87	10.68	13.00	8.28	13.91	12.74
Vermont	17.15	17.01	14.64	14.32	10.19	9.98	–	–	14.46	14.22
Middle Atlantic	15.72	15.27	13.00	12.97	7.25	7.49	12.17	12.50	12.90	12.75
New Jersey	15.72	15.78	12.80	12.78	10.71	10.52	10.43	9.77	13.70	13.68
New York	18.84	17.62	15.23	15.06	6.29	6.70	13.63	14.20	15.62	15.15
Pennsylvania	12.82	12.75	9.26	9.44	7.00	7.23	7.82	8.07	9.83	9.91
East North Central	12.01	12.05	9.51	9.46	6.57	6.51	5.71	6.33	9.33	9.27
Illinois	10.25	11.37	7.88	7.99	5.73	5.80	5.44	6.15	7.99	8.40
Indiana	10.84	10.53	9.48	9.14	6.59	6.34	9.87	9.38	6.83	6.29
Michigan	14.59	14.13	11.07	10.93	7.78	7.62	9.92	8.08	11.26	10.98
Ohio	11.91	11.76	9.38	9.47	6.10	6.24	6.61	6.98	9.16	9.12
Wisconsin	13.70	13.19	10.84	10.51	7.54	7.34	–	–	10.64	10.28
West North Central	10.95	10.59	8.95	8.48	6.60	6.28	8.78	7.72	8.96	8.54
Iowa	11.15	10.82	8.47	8.01	5.66	5.30	–	–	8.12	7.71
Kansas	11.56	11.24	9.54	9.24	7.07	7.09	–	–	9.57	9.33
Minnesota	11.94	11.35	9.53	8.84	7.06	6.54	9.79	8.67	9.52	8.86
Missouri	10.52	10.17	8.72	8.20	6.14	5.89	7.90	6.97	8.96	8.53
Nebraska	10.31	10.04	8.62	8.38	7.22	7.01	–	–	8.69	8.37
North Dakota	9.10	9.06	8.31	8.02	7.20	6.55	–	–	8.19	7.83
South Dakota	10.26	10.07	8.44	8.10	6.93	6.57	–	–	8.83	8.49
South Atlantic	11.37	11.38	9.39	9.37	6.48	6.55	8.66	8.44	9.73	9.73
Delaware	13.01	13.58	10.26	10.13	8.50	8.36	–	–	10.98	11.06
District of Columbia	12.56	12.28	11.93	12.02	5.89	5.46	9.58	9.01	11.85	11.85
Florida	11.36	11.42	9.49	9.66	7.68	8.04	8.69	8.45	10.30	10.44
Georgia	11.24	11.17	9.84	9.58	6.11	5.98	8.03	7.65	9.53	9.37
Maryland	13.24	12.84	10.70	10.43	8.36	8.09	8.48	8.29	11.65	11.28
North Carolina	10.91	10.91	8.73	8.66	6.34	6.42	7.94	7.88	9.18	9.15
South Carolina	11.82	11.77	9.62	9.63	5.92	6.02	–	–	9.14	9.10
Virginia	10.93	11.08	8.05	8.08	6.65	6.72	8.17	8.51	9.01	9.07
West Virginia	9.52	9.85	8.16	8.42	6.20	6.33	8.68	8.66	7.91	8.14
East South Central	10.42	10.32	9.82	9.87	5.96	6.11	11.46	11.28	8.71	8.58
Alabama	11.27	11.40	10.50	10.63	5.99	6.22	–	–	9.02	9.18
Kentucky	9.71	9.43	8.50	8.73	5.40	5.35	–	–	7.54	7.26
Mississippi	10.82	10.26	10.21	9.33	6.45	6.24	–	–	9.15	8.60
Tennessee	10.04	10.10	10.01	10.31	6.44	7.08	11.46	11.28	9.22	9.27
West South Central	10.73	10.30	8.11	7.99	5.86	5.39	10.02	10.30	8.47	8.11
Arkansas	9.51	9.30	7.96	7.71	5.88	5.76	NM	11.23	7.82	7.62
Louisiana	9.39	8.37	8.94	7.75	5.89	4.76	9.45	8.72	8.00	6.90
Oklahoma	9.82	9.51	7.71	7.32	5.34	5.09	–	–	7.81	7.54
Texas	11.37	10.98	8.03	8.16	5.93	5.57	10.12	10.54	8.77	8.55
Mountain	11.32	10.94	9.37	8.99	6.46	6.18	10.47	9.62	9.18	8.82
Arizona	11.74	11.29	9.87	9.53	6.69	6.53	–	–	10.16	9.81
Colorado	11.87	11.46	9.87	9.39	7.22	6.95	10.55	9.69	9.80	9.39
Idaho	9.37	8.67	7.40	6.86	6.12	5.48	–	–	7.61	6.92
Montana	10.38	10.08	9.52	9.13	5.37	5.10	–	–	8.58	8.25
Nevada	11.89	11.83	9.02	8.83	6.52	6.48	8.47	8.40	9.04	8.95
New Mexico	11.69	11.37	9.78	9.32	6.32	5.83	–	–	9.24	8.83
Utah	10.42	9.93	8.37	8.06	5.88	5.62	10.68	9.79	8.18	7.84
Wyoming	10.18	9.85	8.60	8.24	6.41	6.03	–	–	7.55	7.19
Pacific Contiguous	13.60	12.94	12.77	11.92	8.20	7.78	7.72	7.21	12.07	11.38
California	16.39	15.34	14.57	13.41	11.17	10.49	7.68	7.17	14.57	13.53
Oregon	9.94	9.80	8.39	8.31	5.86	5.59	8.88	8.24	8.39	8.21
Washington	8.67	8.53	7.76	7.68	4.22	4.13	8.29	6.06	7.06	6.94
Pacific Noncontiguous	28.59	28.76	25.52	25.50	26.08	26.99	–	–	26.61	26.96
Alaska	18.19	17.88	15.62	14.93	15.77	16.82	–	–	16.52	16.33
Hawaii	36.99	37.34	34.06	34.88	29.87	30.82	–	–	33.27	34.04
U.S. Total	12.12	11.88	10.29	10.09	6.82	6.67	10.28	10.21	10.08	9.84

Displayed values of zero may represent small values that round to zero. The Excel version of this table provides additional precision which may be accessed by selecting individual cells.

Notes: - See Glossary for definitions. - Values for 2012 are final. Values for 2013 are preliminary estimates based on a cutoff model sample.

See Technical Notes for a discussion of the sample design for the Form EIA-826.

Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule.

Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications.

Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report.

Source: U.S. Energy Information Administration, Electric Power Monthly, available at http://www.eia.gov/electricity/monthly/