ITC Holdings Corp.
Form 10-K
February 22, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)

þ	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
	For the fiscal year ended December 31, 2011

OR

o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number: 001-32576
ITC HOLDINGS CORP.
(Exact Name of Registrant as Specified in Its Charter)

Michigan	32-0058047
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

27175 Energy Way
Novi, Michigan 48377
(Address Of Principal Executive Offices, Including Zip Code)
(248) 946-3000
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, without par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes o No þ

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information, statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller Reporting Company o

(Do not check if a smaller reporting company)

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

The aggregate market value of the registrant's common stock held by non-affiliates on June 30, 2011 was approximately $3.7 billion, based on the closing sale price as reported on the New York Stock Exchange. For purposes of this computation, all executive officers, directors and 10% beneficial owners of the registrant are assumed to be affiliates. Such determination should not be deemed an admission that such officers, directors and beneficial owners are, in fact, affiliates of the registrant.

The number of shares of the Registrant's Common Stock, without par value, outstanding as of February 17, 2012 was 51,345,012.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement for the Registrant's 2012 Annual Meeting of Shareholders (the "Proxy Statement") filed pursuant to Regulation 14A are incorporated by reference in Part III of this Form 10-K.

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DEFINITIONS

Unless otherwise noted or the context requires, all references in this report to:

ITC Holdings Corp. and its subsidiaries

- “ITC Great Plains” are references to ITC Great Plains, LLC, a wholly-owned subsidiary of ITC Grid Development, LLC;
- “ITC Grid Development” are references to ITC Grid Development, LLC, a wholly-owned subsidiary of ITC Holdings;
- “Green Power Express” are references to Green Power Express LP, an indirect wholly-owned subsidiary of ITC Holdings;
- “ITC Holdings” are references to ITC Holdings Corp. and not any of its subsidiaries;
- “ITC Midwest” are references to ITC Midwest LLC, a wholly-owned subsidiary of ITC Holdings;
- “ITCTransmission” are references to International Transmission Company, a wholly-owned subsidiary of ITC Holdings;
- “METC” are references to Michigan Electric Transmission Company, LLC, a wholly-owned subsidiary of MTH;
- “MISO Regulated Operating Subsidiaries” are references to ITCTransmission, METC and ITC Midwest together;
- “MTH” are references to Michigan Transco Holdings, LLC, the sole member of METC and an indirect wholly-owned subsidiary of ITC Holdings;
- “Regulated Operating Subsidiaries” are references to ITCTransmission, METC, ITC Midwest and ITC Great Plains together; and
- “We,” “our” and “us” are references to ITC Holdings together with all of its subsidiaries.

Other definitions

- “Consumers Energy” are references to Consumers Energy Company, a wholly-owned subsidiary of CMS Energy Corporation;
- “Detroit Edison” are references to The Detroit Edison Company, a wholly-owned subsidiary of DTE Energy;
- “DTE Energy” are references to DTE Energy Company;
- “Entergy” are references to Entergy Corporation;
- “FERC” are references to the Federal Energy Regulatory Commission;
- “FPA” are references to the Federal Power Act;
- “ICC” are references to the Illinois Commerce Commission;
- “IP&L” are references to Interstate Power and Light Company, an Alliant Energy Corporation subsidiary;
- “ISO” are references to Independent System Operators;
- “IUB” are references to the Iowa Utilities Board;
- “KCC” are references to the Kansas Corporation Commission;
- “kV” are references to kilovolts (one kilovolt equaling 1,000 volts);
- “kW” are references to kilowatts (one kilowatt equaling 1,000 watts);
- “MISO” are references to the Midwest Independent Transmission System Operator, Inc., a FERC-approved RTO which oversees the operation of the bulk power transmission system for a substantial portion of the Midwestern United States and Manitoba, Canada, and of which ITCTransmission, METC and ITC Midwest are members;
- “MOPSC” are references to the Missouri Public Service Commission;
- “MPSC” are references to the Michigan Public Service Commission;
- “MPUC” are references to the Minnesota Public Utilities Commission;
- “MW” are references to megawatts (one megawatt equaling 1,000,000 watts);
- “NERC” are references to the North American Electric Reliability Corporation;

- “NOLs” are references to net operating loss carryforwards for income taxes;
- “OCC” are references to Oklahoma Corporation Commission;
- “RTO” are references to Regional Transmission Organizations; and
- “SPP” are references to Southwest Power Pool, Inc., a FERC-approved RTO which oversees the operation of the bulk power transmission system for a substantial portion of the South Central United States, and of which ITC Great Plains is a member.

PART I

ITEM 1. BUSINESS.

Overview

Our business consists primarily of the electric transmission operations of our Regulated Operating Subsidiaries. In 2002, ITC Holdings was incorporated in the State of Michigan for the purpose of acquiring ITCTransmission. ITCTransmission was originally formed in 2001 as a subsidiary of Detroit Edison, an electric utility subsidiary of DTE Energy, and was acquired in 2003 by ITC Holdings. METC was originally formed in 2001 as a subsidiary of Consumers Energy, an electric and gas utility subsidiary of CMS Energy Corporation, and was acquired in 2006 by ITC Holdings. ITC Midwest was formed in 2007 by ITC Holdings to acquire the transmission assets of IP&L in December 2007. ITC Great Plains was formed in 2006 by ITC Holdings and became a FERC-jurisdictional entity in 2009 after acquiring certain electric transmission assets in Kansas. We operate high-voltage systems in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri and Kansas that transmit electricity from generating stations to local distribution facilities connected to our systems.

Our business strategy is to operate, maintain and invest in transmission infrastructure in order to enhance system integrity and reliability, to reduce transmission constraints and to allow new generating resources to interconnect to our transmission systems. We also are pursuing development projects not within our existing systems, which are also intended to improve overall grid reliability, reduce transmission constraints and facilitate interconnections of new generating resources, as well as to enhance competitive wholesale electricity markets.

As electric transmission utilities with rates regulated by the FERC, our Regulated Operating Subsidiaries earn revenues through tariff rates charged for the use of their electric transmission systems by our customers, which include investor-owned utilities, municipalities, cooperatives, power marketers and alternative energy suppliers. As independent transmission companies, our Regulated Operating Subsidiaries are subject to rate regulation only by the FERC. The rates charged by our Regulated Operating Subsidiaries are established using cost-based formula rate templates as discussed in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism."

Development of Business

We are actively developing transmission infrastructure required to meet reliability needs and emerging long-term energy policy. Our long-term growth plan includes continued investment in current transmission systems, generator interconnections, and our ongoing development projects. Refer to "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Investment and Operating Results Trends" for additional details about our five-year capital investment program totaling $4.2 billion for the period 2012 through 2016. In addition, we have entered into definitive agreements whereby the electric transmission business of Entergy will be merged with a wholly-owned subsidiary of ITC Holdings ("Entergy Transaction") as discussed under "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Project Updates and Other Recent Developments." Finally, refer to the discussion of risks associated with our strategic development opportunities in "Item 1A Risk Factors — Our Regulated Operating Subsidiaries' actual capital expenditures may be lower than planned, which would decrease expected rate base and therefore our revenues. In addition, we expect to invest in strategic development opportunities to improve the efficiency and reliability of the transmission grid, but we cannot assure you that we will be able to initiate or complete any of these investments."

Current Transmission Systems

We expect to invest approximately $1.6 billion from 2012 through 2016 at our Regulated Operating Subsidiaries in order to maintain and replace the current transmission infrastructure, enhance system integrity and reliability and accommodate load growth.

Generator Interconnections

We expect to invest approximately $0.9 billion from 2012 through 2016 to develop and build transmission infrastructure to support generator interconnections.

In 2010, we received MISO approval of the Thumb Loop Project which is primarily located in ITCTransmission's region. The Thumb Loop Project is a 140-mile, double-circuit 345 kV transmission line and related substations that will serve as the backbone of the transmission system needed to accommodate future wind development projects in the Michigan counties of Tuscola, Huron, Sanilac and St. Clair.

Based on the anticipated growth of generating resources, we also foresee the need to construct additional transmission facilities that will provide interconnection opportunities for those wind facilities. The backbone transmission network, transmission for wind interconnection and for interconnection of other generating facilities may provide additional investment opportunities.

Development Projects

We expect to invest approximately $1.7 billion from 2012 through 2016 to construct our portions of various development projects that we are currently advancing in the South Central and North Central regions of the country. We are pursuing strategic development opportunities for transmission investments related to upgrading the existing transmission grid and regional transmission facilities, primarily to improve overall grid reliability, reduce transmission constraints, enhance competitive markets and facilitate interconnections of new generating resources, including wind generation and other renewable resources.

South Central Region

We have pursued the opportunity to invest in two projects in Kansas, through ITC Great Plains, known as the Spearville-Knoll-Axtell transmission project (the "KETA Project") and the Kansas V-Plan Project transmission project running from the Spearville substation to Medicine Lodge, Kansas.

Additionally, ITC Great Plains is in advanced stages of construction for the Hugo to Valliant Project in Oklahoma. ITC Great Plains has established a formula rate for these three projects and other projects within the SPP region.

North Central Region

In 2009, we announced the Green Power Express project, consisting of transmission line segments that would facilitate the movement of power from the Dakotas, Minnesota and Iowa to Midwest load centers that demand energy. Since the announcement of the Green Power Express project, MISO undertook its Regional Generation Outlet Study ("RGOS") to promote investments in new regional transmission infrastructure and implemented its Multi-Value Project ("MVP") cost allocation methodology that better align the costs of MVPs with the benefits associated with them. MISO's RGOS and MVP processes provide a channel for the Green Power Express project, or its underlying segments, to move forward through the planning approval process as MVPs. In December 2011, MISO approved the first portfolio of MVPs identified through the RGOS which includes portions of four MVPs that we intend to build, own and operate. The four MVPs are located in south central Minnesota, portions of Iowa, southwest Wisconsin, and northeast Missouri.

Segments

We have one reportable segment consisting of our Regulated Operating Subsidiaries. Additionally, we have other subsidiaries focused primarily on business development activities and a holding company whose activities include corporate debt and equity financings and general corporate activities. A more detailed discussion of our reportable segment, including financial information about the segment, is included in Note 18 to the consolidated financial statements.

Operations

As transmission-only companies, our Regulated Operating Subsidiaries function as conduits, allowing for power from generators to be transmitted to local distribution systems either entirely through their own systems or in conjunction with neighboring transmission systems. Third parties then transmit power through these local distribution systems to end-use consumers. The transmission of electricity by our Regulated Operating Subsidiaries is a central function to the provision of electricity to residential, commercial and industrial end-use consumers. The operations performed by our Regulated Operating Subsidiaries fall into the following categories:

- asset planning;
- engineering, design and construction;
- maintenance; and
- real time operations.

Asset Planning

Our Asset Planning group uses detailed system models and long-term load forecasts to develop our system expansion capital plans. The expansion plans identify projects that would address potential future reliability issues and/or produce economic savings for customers by eliminating constraints.

Asset Planning works closely with MISO and SPP in the development of our system expansion capital plans by performing technical evaluations and detailed studies. As the regional planning authorities, MISO and SPP approve regional system improvement plans which include projects to be constructed by their members, including our Regulated Operating Subsidiaries.

Engineering, Design and Construction

Our Engineering, Design and Construction group is responsible for design, equipment specifications, maintenance plans and project engineering for capital, operation and maintenance work. We work with outside contractors to perform some of our engineering and design and all of our construction, but retain internal technical experts who have experience with respect to the key elements of the transmission system such as substations, lines, equipment and protective relaying systems.

Maintenance

We develop and track preventive maintenance plans to promote safe and reliable systems. By performing preventive maintenance on our assets, we can minimize the need for reactive maintenance, resulting in improved reliability. Our Regulated Operating Subsidiaries contract with Utility Lines Construction ("ULC"), which is a division of Asplundh Tree Expert Co., to perform the majority of their maintenance. The agreement provides us with access to an experienced and scalable workforce with knowledge of our system at an established rate. In January 2012, we gave notice to ULC that we intend to terminate the agreement for all of our Regulated Operating Subsidiaries upon the conclusion of the six month notice period stipulated in the contracts. We are in the process of negotiating and expect to enter into new agreements with the same supplier prior to the end of the notice period and do not anticipate any disruption in maintenance services.

Real Time Operations

System Operations. From our operations facility in Novi, Michigan, transmission system operators continuously monitor the performance of the transmission systems of our MISO Regulated Operating Subsidiaries, using software and communication systems to perform analysis to plan for contingencies and maintain security and reliability following any unplanned events on the system. Transmission system operators are also responsible for the switching and protective tagging function, taking equipment in and out of service to ensure capital construction projects and maintenance programs can be completed safely and reliably. Similar system operations services for ITC Great Plains will be provided as new transmission lines are placed in service.

Local Balancing Authority Operator. Under the functional control of MISO, ITCTransmission and METC operate their electric transmission systems as a combined Local Balancing Authority ("LBA") area, known as the Michigan Electric Coordinated Systems ("MECS"). From our operations facility in Novi, Michigan, our employees perform the LBA functions as outlined in MISO's Balancing Authority Agreement. These functions include actual interchange data administration and verification and MECS LBA area emergency procedure implementation and coordination. ITC Midwest and ITC Great Plains are not responsible for LBA functions for their respective assets.

Operating Contracts

Our Regulated Operating Subsidiaries have various operating contracts, including numerous interconnection agreements with generation and transmission providers that address terms and conditions of interconnection. The following significant agreements exist at our Regulated Operating Subsidiaries:

ITCTransmission

Detroit Edison operates the electric distribution system to which ITCTransmission's transmission system connects. A set of three operating contracts sets forth the terms and conditions related to Detroit Edison's and ITCTransmission's ongoing working relationship. These contracts include the following:

Master Operating Agreement. The Master Operating Agreement (the "MOA"), dated as of February 28, 2003, governs the primary day-to-day operational responsibilities of ITCTransmission and Detroit Edison and will remain in effect until terminated by mutual agreement of the parties (subject to any required FERC approvals) unless earlier terminated pursuant to its terms. The MOA identifies the control area coordination services that ITCTransmission is obligated to provide to Detroit Edison. The MOA also requires Detroit Edison to provide certain generation-based support services to ITCTransmission.

Generator Interconnection and Operation Agreement. Detroit Edison and ITCTransmission entered into the Generator Interconnection and Operation Agreement (the "GIOA"), dated as of February 28, 2003, in order to establish, re-establish and maintain the direct electricity interconnection of Detroit Edison's electricity generating assets with ITCTransmission's transmission system for the purposes of transmitting electric power from and to the electricity generating facilities. Unless otherwise terminated by mutual agreement of the parties (subject to any required FERC approvals), the GIOA will remain in effect until Detroit Edison elects to terminate the agreement with respect to a particular unit or until a particular unit ceases commercial operation.

Coordination and Interconnection Agreement. The Coordination and Interconnection Agreement (the "CIA"), dated as of February 28, 2003, governs the rights, obligations and responsibilities of ITCTransmission and Detroit Edison regarding, among other things, the operation and interconnection of Detroit Edison's distribution system and

ITCTransmission's transmission system, and the construction of new facilities or modification of existing facilities. Additionally, the CIA allocates costs for operation of supervisory, communications and metering equipment. The CIA will remain in effect until terminated by mutual agreement of the parties (subject to any required FERC approvals).

METC

Consumers Energy operates the electric distribution system to which METC's transmission system connects. METC is a party to a number of operating contracts with Consumers Energy that govern the operations and maintenance of its transmission system.

These contracts include the following:

Amended and Restated Easement Agreement. Under the Amended and Restated Easement Agreement (the “Easement Agreement”), dated as of April 29, 2002 and as further supplemented, Consumers Energy provides METC with an easement to the land, which we refer to as premises, on which a majority of METC’s transmission towers, poles, lines and other transmission facilities used to transmit electricity at voltages of at least 120 kV are located, which we refer to collectively as the facilities. Consumers Energy retained for itself the rights to, and the value of activities associated with, all other uses of the premises and the facilities covered by the Easement Agreement, such as for distribution of electricity, fiber optics, telecommunications, gas pipelines and agricultural uses. Accordingly, METC is not permitted to use the premises or the facilities covered by the Easement Agreement for any purposes other than to provide electric transmission and related services, to inspect, maintain, repair, replace and remove electric transmission facilities and to alter, improve, relocate and construct additional electric transmission facilities. The easement is further subject to the rights of any third parties that had rights to use or occupy the premises or the facilities prior to April 1, 2001 in a manner not inconsistent with METC’s permitted uses.

METC pays Consumers Energy annual rent of $10.0 million, in equal quarterly installments, for the easement and related rights under the Easement Agreement. Although METC and Consumers Energy share the use of the premises and the facilities covered by the Easement Agreement, METC pays the entire amount of any rentals, property taxes, inspection fees and other amounts required to be paid to third parties with respect to any use, occupancy, operations or other activities on the premises or the facilities and is generally responsible for the maintenance of the premises and the facilities used for electric transmission at its expense. METC also must maintain commercial general liability insurance protecting METC and Consumers Energy against claims for personal injury, death or property damage occurring on the premises or the facilities and pay for all insurance premiums. METC is also responsible for patrolling the premises and the facilities by air at its expense at least annually and to notify Consumers Energy of any unauthorized uses or encroachments discovered. METC must indemnify Consumers Energy for all liabilities arising from the facilities covered by the Easement Agreement.

METC must notify Consumers Energy before altering, improving, relocating or constructing additional transmission facilities covered by the Easement Agreement. Consumers Energy may respond by notifying METC of reasonable work and design restrictions and precautions that are needed to avoid endangering existing distribution facilities, pipelines or communications lines, in which case METC must comply with these restrictions and precautions. METC has the right at its own expense to require Consumers Energy to remove and relocate these facilities, but Consumers Energy may require payment in advance or the provision of reasonable security for payment by METC prior to removing or relocating these facilities, and Consumers Energy need not commence any relocation work until an alternative right-of-way satisfactory to Consumers Energy is obtained at METC’s expense.

The term of the Easement Agreement runs through December 31, 2050 and is subject to 10 automatic 50-year renewals after that time unless METC provides one year’s notice of its election not to renew the term. Consumers Energy may terminate the Easement Agreement 30 days after giving notice of a failure by METC to pay its quarterly installment if METC does not cure the non-payment within the 30-day notice period. At the end of the term or upon any earlier termination of the Easement Agreement, the easement and related rights terminate and the transmission facilities revert to Consumers Energy.

Amended and Restated Operating Agreement. Under the Amended and Restated Operating Agreement (the “Operating Agreement”), dated as of April 29, 2002, METC agrees to operate its transmission system to provide all transmission customers with safe, efficient, reliable and nondiscriminatory transmission service pursuant to its tariff. Among other things, METC is responsible under the Operating Agreement for maintaining and operating its transmission system, providing Consumers Energy with information and access to its transmission system and related books and records, administering and performing the duties of control area operator (that is, the entity exercising operational control over the transmission system) and, if requested by Consumers Energy, building connection facilities necessary to permit interaction with new distribution facilities built by Consumers Energy. Consumers Energy has corresponding obligations to provide METC with access to its books and records and to build distribution facilities necessary to provide adequate and reliable transmission services to wholesale customers. Consumers Energy must cooperate with METC as METC performs its duties as control area operator, including by providing reactive supply and voltage control from generation sources or other ancillary services and reducing load. The Operating Agreement is effective through 2050 and is subject to 10 automatic 50-year renewals after that time, unless METC provides one year's notice of its election not to renew.

Amended and Restated Purchase and Sale Agreement for Ancillary Services. The Amended and Restated Purchase and Sale Agreement for Ancillary Services (the "Ancillary Services Agreement") is dated as of April 29, 2002. Since METC does not own any generating facilities, it must procure ancillary services from third party suppliers, such as Consumers Energy. Currently, under the Ancillary Services Agreement, METC pays Consumers Energy for providing certain generation based services necessary to support the reliable operation of the bulk power grid, such as voltage support and generation capability and capacity to balance loads and generation. METC is not precluded from procuring these ancillary services from third party suppliers when available. The Ancillary Services Agreement is subject to rolling one-year renewals starting May 1, 2003, unless terminated by either METC or Consumers Energy with six months prior written notice.

Amended and Restated Distribution-Transmission Interconnection Agreement. The Amended and Restated Distribution-Transmission Interconnection Agreement (the “DT Interconnection Agreement”), dated April 29, 2002 and amended most recently effective as of September 1, 2010, provides for the interconnection of Consumers Energy’s distribution system with METC’s transmission system and defines the continuing rights, responsibilities and obligations of the parties with respect to the use of certain of their own and the other party’s properties, assets and facilities. METC agrees to provide Consumers Energy interconnection service at agreed-upon interconnection points, and the parties have mutual responsibility for maintaining voltage and compensating for reactive power losses resulting from their respective services. The DT Interconnection Agreement is effective so long as any interconnection point is connected to METC, unless it is terminated earlier by mutual agreement of METC and Consumers Energy.
Amended and Restated Generator Interconnection Agreement. The Amended and Restated Generator Interconnection Agreement (the “Generator Interconnection Agreement”), dated as of April 29, 2002 and amended most recently effective as of August 1, 2011, specifies the terms and conditions under which Consumers Energy and METC maintain the interconnection of Consumers Energy’s generation resources and METC’s transmission assets. The Generator Interconnection Agreement is effective either until it is replaced by any MISO-required contract, or until mutually agreed by METC and Consumers Energy to terminate, but not later than the date that all listed generators cease commercial operation.

ITC Midwest

IP&L operates the electric distribution system to which ITC Midwest’s transmission system connects. ITC Midwest is a party to a number of operating contracts with IP&L that govern the operations and maintenance of its transmission system. These contracts include the following:
Distribution-Transmission Interconnection Agreement. The Distribution-Transmission Interconnection Agreement (the “DTIA”), dated as of December 17, 2007, governs the rights, responsibilities and obligations of ITC Midwest and IP&L, with respect to the use of certain of their own and the other parties’ property, assets and facilities, and the construction of new facilities or modification of existing facilities. Additionally, the DTIA sets forth the terms pursuant to which the equipment and facilities and the interconnection equipment of IP&L will continue to connect ITC Midwest’s facilities through which ITC Midwest provides transmission service under the MISO Transmission and Energy Markets Tariff. The DTIA will remain in effect until terminated by mutual agreement by the parties (subject to any required FERC approvals) or as long as any interconnection point of IP&L is connected to ITC Midwest’s facilities, unless modified by written agreement of the parties.
Large Generator Interconnection Agreement. ITC Midwest, IP&L and MISO entered into the Large Generator Interconnection Agreement (the “LGIA”), dated as of December 20, 2007, in order to establish, re-establish and maintain the direct electricity interconnection of IP&L’s electricity generating assets with ITC Midwest’s transmission system for the purposes of transmitting electric power from and to the electricity generating facilities. The LGIA will remain in effect until terminated by ITC Midwest or until IP&L elects to terminate the agreement if a particular unit ceases commercial operation for three consecutive years.
Operations Services Agreement For 34.5 kV Transmission Facilities. ITC Midwest and IP&L entered into the Operations Services Agreement for 34.5 kV Transmission Facilities (the “OSA”), effective as of January 1, 2011, under which IP&L performs certain operations functions for ITC Midwest’s 34.5 kV transmission system on behalf of ITC Midwest. The OSA will remain in full force and effect until December 31, 2015 and will extend automatically from year to year thereafter until terminated by either party upon not less than one year prior written notice to the other party.

ITC Great Plains

Amended and Restated Maintenance Agreement. Mid-Kansas Electric Company LLC (“Mid-Kansas”) and ITC Great Plains have entered into a Maintenance Agreement (the “Mid-Kansas Agreement”), dated as of August 24, 2010, pursuant to which Mid-Kansas has agreed to perform various field operations and maintenance services related to the ITC Great Plains Elm Creek and Flat Ridge Substations, which ITC Great Plains purchased from Mid-Kansas. The Mid-Kansas Agreement has an initial term of 10 years and automatic 10-year renewals unless terminated (1) due to a breach by the non-terminating party following notice and failure to cure, (2) by mutual consent of the parties, or (3) by ITC Great Plains under certain limited circumstances. Services must continue to be provided for at least six months subsequent to the termination date in any case.

Regulatory Environment

Many regulators and public policy makers support the need for further investment in the transmission grid. The growth in electricity generation, wholesale power sales and consumption combined with historically inadequate transmission investment have resulted in significant transmission constraints across the United States and increased stress on aging equipment. These problems will continue without increased investment in transmission infrastructure. Transmission system investments can also increase system reliability and reduce the frequency of power outages. Such investments can reduce transmission constraints and improve access to lower cost generation resources, resulting in a lower overall cost of delivered electricity for end-use consumers. After the 2003 blackout that affected sections of the Northeastern and Midwestern United States and Ontario, Canada, the

Department of Energy (the “DOE”) established the Office of Electric Transmission and Distribution, focused on working with reliability experts from the power industry, state governments, and their Canadian counterparts to improve grid reliability and increase investment in the country’s electric infrastructure. In addition, the FERC has signaled its desire for substantial new investment in the transmission sector by implementing various financial and other incentives.

The FERC has also issued orders to promote non-discriminatory transmission access for all transmission customers. In the United States, electric transmission assets are predominantly owned, operated and maintained by utilities that also own electricity generation and distribution assets, known as vertically integrated utilities. The FERC has recognized that the vertically-integrated utility model inhibits the provision of non-discriminatory transmission access and, in order to alleviate this potential discrimination, the FERC has mandated that all transmission systems over which it has jurisdiction must be operated in a comparable, non-discriminatory manner such that any seller of electricity affiliated with a transmission owner or operator is not provided with preferential treatment. The FERC has also indicated that independent transmission companies can play a prominent role in furthering its policy goals and has encouraged the legal and functional separation of transmission operations from generation and distribution operations.

On August 8, 2005, the Energy Policy Act was enacted, which requires the FERC to implement mandatory electric transmission reliability standards to be enforced by an Electric Reliability Organization. Effective June 2007, the FERC approved mandatory adoption of certain reliability standards and approved enforcement actions for violators, including fines of up to $1.0 million per day. The NERC was assigned the responsibility of developing and enforcing these mandatory reliability standards. We continually assess our transmission systems against standards established by the NERC, as well as the standards of applicable regional entities under the NERC that have been delegated certain authority for the purpose of proposing and enforcing reliability standards. Finally, the Energy Policy Act repealed the Public Utility Holding Company Act of 1935, which was replaced by the Public Utility Holding Company Act of 2005. It also subjected utility holding companies to regulations of the FERC related to access to books and records, and amended Section 203 of the FPA to provide explicit authority for the FERC to review mergers and consolidations involving utility holding companies in certain circumstances.

Federal Regulation

As electric transmission companies, our Regulated Operating Subsidiaries are regulated by the FERC. The FERC is an independent regulatory commission within the DOE that regulates the interstate transmission and certain wholesale sales of natural gas, the transmission of oil and oil products by pipeline, and the transmission and wholesale sale of electricity in interstate commerce. The FERC also administers accounting and financial reporting regulations and standards of conduct for the companies it regulates. In 1996, in order to facilitate open access transmission for participants in wholesale power markets, the FERC issued Order No. 888. The open access policy promulgated by the FERC in Order No. 888 was upheld in a United States Supreme Court decision State of New York vs. FERC, issued on March 4, 2002. To facilitate open access, among other things, FERC Order No. 888 encouraged investor owned utilities to cede operational control over their transmission systems to ISOs, which are not-for-profit entities.

As an alternative to ceding operating control of their transmission assets to ISOs, certain investor owned utilities began to promote the formation of for-profit transmission companies, which would assume control of the operation of the grid. In December 1999, the FERC issued Order No. 2000, which strongly encouraged utilities to voluntarily transfer operational control of their transmission systems to RTOs. RTOs, as envisioned in Order No. 2000, would assume many of the functions of an ISO, but the FERC permitted greater flexibility with regard to the organization and structure of RTOs than it had for ISOs. RTOs could accommodate the inclusion of independently owned, for-profit companies that own transmission assets within their operating structure. Independent ownership would facilitate not only the independent operation of the transmission systems but also the formation of companies with a greater financial interest in maintaining and augmenting the capacity and reliability of those systems. RTOs such as MISO and SPP monitor electric reliability and are responsible for coordinating the operation of the wholesale electric transmission system and ensuring fair, non-discriminatory access to the transmission grid.

In July 2011, the FERC issued Order No. 1000 ("Order 1000") which amends certain existing transmission planning and cost allocation requirements to ensure that FERC-jurisdictional services are provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential. With respect to transmission planning, Order 1000: (1) requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) requires that each public utility transmission provider amend its Open Access Transmission Tariff ("OATT") to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; (3) removes from FERC-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) improves coordination between neighboring transmission planning regions for new interregional transmission facilities. Order 1000 could potentially lead to greater competition for certain transmission projects, including within our current operating area. The compliance phase for Order 1000 is expected to take up to 18 months.

Revenue Requirement Calculations and Cost Sharing for Projects with Regional Benefits

The cost based formula rates used by our Regulated Operating Subsidiaries continue to evolve to include revenue requirement calculations for various types of projects. Network revenues continue to be the largest component of revenues recovered through our formula rates. However, regional cost sharing revenues are growing as a result of projects that have been identified by MISO or SPP as having regional benefits, and therefore eligible for regional cost recovery under their tariff. Separate calculations of revenue requirement are performed for projects that have been approved for regional cost sharing and certain of these revenue requirements are subject to an annual true-up. The separate calculations of revenue requirement impact only which parties ultimately pay for the transmission services related to these projects and do not impact our financial results.

We have projects that are eligible for regional cost sharing under Attachment FF of the MISO tariff, such as certain network upgrade projects, and the MVPs, including the Thumb Loop Project. The FERC accepted MISO's Thumb Loop Project MVP filing in 2010. Additionally, certain projects at ITC Great Plains are eligible for recovery through a region-wide charge in the SPP tariff: the KETA Project, which was part of the balanced portfolio of projects approved by SPP in 2009 and the Kansas V-Plan Project, which is subject to SPP's highway/byway cost allocation. The FERC approved SPP's highway/byway cost allocation methodology in 2010. These projects are described in more detail in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Project Updates and Other Recent Developments."

State Regulation

The regulatory agencies in the states where our Regulated Operating Subsidiaries' assets are located do not have jurisdiction over rates or terms and conditions of service. However, they typically have jurisdiction over siting of transmission facilities and related matters as described below. Additionally, we are subject to the regulatory oversight of various state environmental quality departments for compliance with any state environmental standards and regulations.

ITCTransmission and METC

Michigan

The MPSC has jurisdiction over the siting of transmission facilities. Additionally, pursuant to Michigan Public Acts 197 and 198 of 2004, ITCTransmission and METC have the right as independent transmission companies to condemn property in the state of Michigan for the purposes of building or maintaining transmission facilities.

ITCTransmission and METC are also subject to the regulatory oversight of the Michigan Department of Environmental Quality, the Michigan Department of Natural Resources and certain local authorities for compliance with all environmental standards and regulations.

ITC Midwest

Iowa

Iowa Code ch. 478 provides that the IUB has the power of supervision over the construction, operation, and maintenance of transmission facilities in Iowa by any entity, which includes the power to issue franchises. Iowa Code ch. 478 further provides that any entity granted a franchise by the IUB is vested with the power of condemnation in Iowa to the extent the IUB approves and deems necessary for public use. A city has the power, pursuant to Iowa Code ch. 364, to grant a franchise to erect, maintain, and operate transmission facilities within the city, which franchise may regulate the conditions required and manner of use of the streets and public grounds of the city and may confer the power to appropriate and condemn private property.

ITC Midwest also is subject to the regulatory oversight of certain state agencies (including the Iowa Department of Natural Resources) and certain local authorities with respect to the issuance of environmental, highway, railroad, and similar permits.

Minnesota

The MPUC has jurisdiction over the siting and routing of new transmission lines or upgrades of existing lines through Minnesota's Certificate of Need and Route Permit Processes. Transmission companies are also required to participate in the State's Biennial Transmission Planning Process and are subject to the state's preventative maintenance requirements. Pursuant to Minnesota law, ITC Midwest has the right as an independent transmission company to condemn property in the State of Minnesota for the purpose of building new transmission facilities.

ITC Midwest is also subject to the regulatory oversight of the Minnesota Pollution Control Agency, the Minnesota Department of Natural Resources, the MPUC in conjunction with the Department of Commerce/ Office of Energy

Security, and certain local authorities for compliance with applicable environmental standards and regulations.

Illinois

The ICC exercises jurisdiction over siting of new transmission lines through its requirements for Certificates of Public Convenience and Necessity and Right-Of-Way acquisition that apply to construction of new or upgraded facilities. ITC Midwest also is subject to the regulatory oversight of the Illinois Environmental Protection Agency, the Illinois Department of Natural Resources, the Illinois Pollution Control Board and certain local authorities for compliance with all environmental standards and regulations.

Missouri

Because ITC Midwest is a "public utility" and an "electrical corporation" under Missouri law, the MOPSC has jurisdiction to determine whether ITC Midwest may operate in such capacity. In this regard, on August 30, 2007, the MOPSC granted ITC Midwest a certificate of public convenience and necessity to own, operate and maintain a 161 kV transmission line of approximately 9.5 miles located in Clark County, Missouri which connects the substation in Keokuk, Iowa with Ameren Energy Generating Company's transmission substation near Wayland, Missouri. The MOPSC also exercises jurisdiction with regard to other non-rate matters affecting this Missouri asset such as transmission substation construction, general safety and the transfer of the franchise or property.

ITC Midwest is also subject to the regulatory oversight of the Missouri Department of Natural Resources for compliance with all environmental standards and regulations relating to this transmission line.

ITC Great Plains

Kansas

ITC Great Plains is a "public utility" in Kansas and an "electric utility" pursuant to state statutes. The KCC issued an order approving the issuance of a limited certificate of convenience to ITC Great Plains for the purposes of building, owning and operating SPP transmission projects in Kansas. In addition to its certificate authority, the KCC has jurisdiction over the siting of electric transmission lines.

ITC Great Plains is also subject to the regulatory oversight of the Kansas Department of Health and Environment for compliance with all environmental standards and regulations relating to the construction phase of any transmission line.

Oklahoma

On September 11, 2008, ITC Great Plains received approval from the OCC to operate in Oklahoma, pursuant to Oklahoma Statutes as an electric public utility providing only transmission services. The OCC does not exercise jurisdiction over the siting of any transmission lines.

ITC Great Plains may be subject to the regulatory oversight of Oklahoma Department of Environmental Quality for compliance with environmental standards and regulations relating to construction of proposed transmission lines.

ITC Great Plains does not currently own or operate transmission facilities in Oklahoma, but is constructing an approximately 19-mile 345 kV transmission line and associated facilities in southeastern Oklahoma, known as the Hugo to Valliant project.

Sources of Revenue

See "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — Operating Revenues" for a discussion of our principal sources of revenue.

Seasonality

The cost-based formula rates with a true-up mechanism in effect for all our Regulated Operating Subsidiaries, as discussed in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism," mitigate the seasonality of net income for our Regulated Operating Subsidiaries. Our Regulated Operating Subsidiaries accrue or defer revenues to the extent that the actual revenue requirement for the reporting period is higher or lower, respectively, than the amounts billed relating to that reporting period. For example, to the extent that amounts billed are less than our revenue requirement for a reporting period, a revenue accrual is recorded for the difference and the difference results in no net income impact.

Operating cash flows are seasonal at our MISO Regulated Operating Subsidiaries, in that cash received for revenues is typically higher in the summer months when peak load is higher.

Principal Customers

Our principal transmission service customers are Detroit Edison, Consumers Energy and IP&L, which accounted for approximately 30.8%, 26.0% and 25.3%, respectively, of our total operating revenues for the year ended December 31, 2011. One or more of these customers together have consistently represented a significant percentage of our operating revenue. These percentages of total operating revenues of Detroit Edison, Consumers Energy and IP&L include an estimate for the 2011 revenue accruals and deferrals that were included in our 2011 operating revenues, but will not be billed to our customers until 2013. We have assumed that the revenues billed to these customers in 2013 would be in the same proportion of the respective percentages of network and regional cost sharing revenues billed to them in 2011. Our remaining revenues were generated from providing service to other entities such as alternative electricity suppliers, power marketers and other wholesale customers that provide electricity to end-use consumers and from transaction-based capacity reservations. Nearly all of our revenues are from transmission customers in the United States. Although we may recognize allocated revenues from time to time from Canadian entities reserving transmission over the Ontario or Manitoba interface, these revenues have not been and are not expected to be material to us.

Billing

MISO is responsible for billing and collection for transmission services and administers the transmission tariff in the MISO service territory. As the billing agent for our MISO Regulated Operating Subsidiaries, MISO bills Detroit Edison, Consumers Energy, IP&L and other customers on a monthly basis and collects fees for the use of our transmission systems.

SPP is responsible for billing and collection for transmission services and administers the transmission tariff in the SPP service territory of which ITC Great Plains is a member. As the billing agent for ITC Great Plains, SPP independently administers the transmission tariff.

See “Item 7A Quantitative and Qualitative Disclosures about Market Risk — Credit Risk” for discussion of our credit policies.

Competition

Each of our MISO Regulated Operating Subsidiaries is the only transmission system in its respective service area and, therefore, effectively has no competitors. However, the competitive environment may change due to the implementation of Order 1000. See further discussion of Order 1000 above under "Regulatory Environment — Federal Regulation." For our subsidiaries focused on development opportunities for transmission investment in other service areas, the incumbent utilities or other entities with transmission development initiatives may compete with us by seeking regulatory approval to be named the party authorized to build new capital projects that we are also pursuing. Because our Regulated Operating Subsidiaries are currently the only transmission companies that are independent from electricity market participants, we believe we are best able to develop these projects in a non-discriminatory manner. However, there are no assurances we will be selected to develop projects that other entities are also pursuing.

Employees

As of December 31, 2011, we had 452 employees. We consider our relations with our employees to be good.

Environmental Matters

Our operations are subject to federal, state, and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities to investigate or remediate contamination, as well as other liabilities concerning hazardous materials or contamination, such as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as at properties currently owned or operated by us. Such liabilities may arise even where the contamination does not result from noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire share. Environmental requirements generally have become more stringent and compliance with those requirements more expensive. We are not aware of any specific developments that would increase our costs for such compliance in a manner that would be expected to have a material effect on our results of operations, financial position or liquidity.

Our assets and operations also involve the use of materials classified as hazardous, toxic or otherwise dangerous. Many of the properties our Regulated Operating Subsidiaries own or operate have been used for many years, and include older facilities and equipment that may be more likely than newer ones to contain or be made from such materials. Some of these properties include aboveground or underground storage tanks and associated piping. Some of them also include large electrical equipment filled with mineral oil, which may contain or previously have contained polychlorinated biphenyls (commonly known as PCBs). Our facilities and equipment are often situated close to or on property owned by others so that, if they are the source of contamination, the property of others may be affected. For example, aboveground and underground transmission lines sometimes traverse properties that we do not own, and, at some of our transmission stations, transmission assets (owned or operated by us) and distribution assets (owned or operated by our transmission customers) are commingled.

Some properties in which we have an ownership interest or at which we operate are, and others are suspected of being, affected by environmental contamination. We are not aware of any claims pending or threatened against us with respect to environmental contamination, or of any investigation or remediation of contamination at any properties, that entail costs likely to materially affect us. Some facilities and properties are located near environmentally sensitive areas such as wetlands.

Claims have been made or threatened against electric utilities for bodily injury, disease or other damages allegedly related to exposure to electromagnetic fields associated with electric transmission and distribution lines. While we do not believe that a causal link between electromagnetic field exposure and injury has been generally established and accepted in the scientific community, if such a relationship is established or accepted, the liabilities and costs imposed on our business could be significant.

We are not aware of any claims pending or threatened against us for bodily injury, disease or other damages allegedly related to exposure to electromagnetic fields and electric transmission and distribution lines that entail costs likely to have a material adverse effect on our results of operations, financial position or liquidity.

Filings Under the Securities Exchange Act of 1934

Our internet address is http://www.itc-holdings.com. You can access free of charge on our web site all of our reports filed pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports. These reports are available as soon as practicable after they are electronically filed with the Securities and Exchange Commission (the "SEC"). Also on our web site are our:

- Corporate Governance Guidelines;
- Code of Business Conduct and Ethics; and
- Committee Charters for the Audit and Finance Committee, Compensation Committee and Nominating/Corporate Governance Committee.

Our Code of Business Conduct and Ethics applies to all directors, officers and employees, including our Chairman, President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer. We will post any amendments to the Code of Business Conduct and Ethics, and any waivers that are required to be disclosed by the rules of either the SEC or the NYSE, on our web site within the required periods. The information on our web site is not incorporated by reference into this report.

To learn more about us, please visit our website at http://www.itc-holdings.com. We use our website as a channel of distribution of material company information. Financial and other material information regarding us is routinely posted on our website and is readily accessible.

You may also read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington DC, 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address is http://www.sec.gov.

ITEM 1A. RISK FACTORS.

Risks Related to Our Business

Certain elements of our Regulated Operating Subsidiaries' cost recovery through rates can be challenged, which could result in lowered rates and/or refunds of amounts previously collected and thus have an adverse effect on our business, financial condition, results of operations and cash flows. We have also made certain commitments to federal and state regulators with respect to, among other things, our rates in connection with recent acquisitions (including ITC Midwest's acquisition of IP&L's electric transmission assets) that could have an adverse effect on our business, financial condition, results of operations and cash flows.

Our Regulated Operating Subsidiaries provide transmission service under rates regulated by the FERC. The FERC has approved the cost-based formula rate templates used by our Regulated Operating Subsidiaries, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of our Regulated Operating Subsidiaries' rates approved by the FERC, including the formula rate templates, ITCTransmission's, METC's, ITC Midwest's and ITC Great Plains' respective allowed 13.88%, 13.38%, 12.38% and 12.16% rates of return on the actual equity portion of their respective capital structures, and the data inputs provided by our Regulated Operating Subsidiaries for calculation of each year's rate, are subject to challenge by interested parties at the FERC in a proceeding under Section 206 of the FPA. If a challenger can establish that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then the FERC will make appropriate prospective adjustments to them and/or disallow any of our Regulated Operating Subsidiaries' inclusion of those aspects in the rate setting formula. This could result in lowered rates and/or refunds of amounts collected after the date that a Section 206 challenge is filed.

The FERC's order approving our acquisition of METC was conditioned upon ITCTransmission and METC not recovering "merger-related costs" in their rates, as described in the order, unless a separate informational filing is submitted to the FERC. The informational filing, which could be challenged by interested parties, would need to identify those costs and show that such costs are outweighed by the benefits of the acquisition. Determinations by ITCTransmission or METC that expenses included in their formula rate template for recovery are not acquisition related costs are also subject to challenge by interested parties at the FERC. If challenged at the FERC and ITCTransmission or METC fail to show that costs included for recovery are not merger-related, this also could result in lowered rates and/or refunds of amounts collected. We have not sought recovery of merger-related costs at ITCTransmission or METC.

Under the FERC’s order approving ITC Midwest’s asset acquisition, ITC Midwest agreed to a hold harmless commitment in which no acquisition premium will be recovered in rates, nor will ITC Midwest recover through transmission rates any transaction-related costs that exceed demonstrated transaction related savings for a period of five years. If during the five year period ITC Midwest seeks to recover transaction-related costs through its formula rate, ITC Midwest must make an informational filing at the FERC that identifies the transaction-related costs sought to be recovered and demonstrates that those costs are exceeded by transaction-related savings. If challenged at the FERC and ITC Midwest fails to show that transaction-related costs included for recovery do not exceed transaction-related savings, ITC Midwest could be subject to lowered rates and/or refunds of amounts previously collected. Additionally, in Iowa and Minnesota, as part of the regulatory approval process, ITC Midwest committed not to recover the first $15.0 million in transaction-related costs under any circumstances. We have not sought recovery of transaction-related costs at ITC Midwest.

In the Minnesota regulatory proceeding to approve ITC Midwest's December 2007 acquisition of the transmission assets of IP&L, ITC Midwest also agreed to build two transmission projects intended to improve the reliability and efficiency of our electric transmission system. Specifically, ITC Midwest made commitments to use commercially reasonable best efforts to complete these projects prior to December 31, 2009 and 2011, respectively. In the event ITC Midwest is found to have failed to meet these commitments, the allowed 12.38% rate of return on the actual equity portion of ITC Midwest’s capital structure would be reduced to 10.39% until such time as ITC Midwest completes these projects, and ITC Midwest would refund with interest any amounts collected since the close date of the transaction that exceeded what would have been collected if the 10.39% return on equity had been used. The project that was required to be completed prior to December 31, 2009 was completed by that deadline. With respect to the second project, the 345 kV Salem-Hazelton line, certain regulatory approvals were needed from the IUB before construction of the project could commence, but due to the IUB's case schedule, these approvals were not received until the second quarter of 2011. As a result of the delay in the receipt of the necessary regulatory approvals, the project was not completed by December 31, 2011. While we believe we used commercially reasonable best efforts to meet the December 31, 2011 deadline, any of the events described above could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our Regulated Operating Subsidiaries’ actual capital expenditures may be lower than planned, which would decrease expected rate base and therefore our expected revenues and earnings. In addition, we expect to invest in strategic development opportunities to improve the efficiency and reliability of the transmission grid, but we cannot assure you that we will be able to initiate or complete any of these investments.

Each of our Regulated Operating Subsidiaries’ rate base, revenues and earnings are determined in part by additions to property, plant and equipment when placed in service. We anticipate making significant capital investments over the next five years which include estimated transmission network upgrades for generator interconnections. The amounts for network upgrades could change significantly due to factors beyond our control, such as changes in the MISO queue for generation projects and whether the generator meets the various criteria of Attachment FF of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff for the project to qualify as a refundable network upgrade, among other factors. If our Regulated Operating Subsidiaries’ capital expenditures and the resulting in-service property, plant and equipment are lower than anticipated for any reason, our Regulated Operating Subsidiaries will have a lower than anticipated rate base thus causing their revenue requirements and future earnings to be potentially lower than anticipated.

In addition, we are pursuing broader strategic development investment opportunities for transmission construction related to building regional transmission facilities, interconnections for generating resources, and other investment opportunities. The incumbent utilities or other entities with transmission development initiatives may compete with us by deciding to pursue capital projects that we are pursuing. These estimates of potential investment opportunities are based primarily on foreseeable transmission needs and general transmission construction costs, not necessarily on particular project cost estimates.

Any capital investment at our Regulated Operating Subsidiaries or as a result of our broader strategic development initiatives may be lower than expected due to, among other factors, the impact of actual loads, forecasted loads, regional economic conditions, weather conditions, union strikes, labor shortages, material and equipment prices and availability, our ability to obtain financing for such expenditures, if necessary, limitations on the amount of construction that can be undertaken on our system or transmission systems owned by others at any one time, regulatory approvals for reasons relating to rate construct, environmental, siting, regional planning, cost recovery or other issues or as a result of legal proceedings and variances between estimated and actual costs of construction contracts awarded. Our ability to engage in construction projects resulting from pursuing these initiatives is subject to significant uncertainties, including the factors discussed above, and will depend on obtaining any necessary regulatory and other approvals for the project and for us to initiate construction, our achieving status as the builder of the project in some circumstances and other factors. Therefore, we can provide no assurance as to the actual level of investment we may achieve at our Regulated Operating Subsidiaries or as a result of the broader strategic development initiatives.

The regulations to which we are subject may limit our ability to raise capital and/or pursue acquisitions, development opportunities or other transactions or may subject us to liabilities.
Each of our Regulated Operating Subsidiaries is a “public utility” under the FPA and, accordingly, is subject to regulation by the FERC. Approval of the FERC is required under Section 203 of the FPA for a disposition or acquisition of regulated public utility facilities, either directly or indirectly through a holding company. Such approval may also be required to acquire securities in a public utility. Section 203 of the FPA also provides the FERC with explicit authority over utility holding companies’ purchases or acquisitions of, and mergers or consolidations with, a public utility. Finally, each of our Regulated Operating Subsidiaries must also seek approval by the FERC under Section 204 of the FPA for issuances of its securities (including debt securities).
We are also pursuing strategic development opportunities for construction of transmission facilities and interconnections with generating resources. These projects require regulatory approval by the FERC, applicable RTOs and state regulatory agencies. Failure to secure such regulatory approval for new strategic development projects could adversely affect our ability to grow our business and increase our revenues. In addition, we are subject to state and/or local regulations relating to, among other things, facility siting. If we fail to comply with these local regulations, we may incur liabilities for such failure.
Changes in federal energy laws, regulations or policies could impact cash flows and could reduce the dividends we may be able to pay our stockholders.
The formula rate templates used by our Regulated Operating Subsidiaries to calculate their respective annual revenue requirements will be used by our Regulated Operating Subsidiaries for that purpose until and unless the FERC determines that such rate formula is unjust and unreasonable or that another mechanism is more appropriate. Such determinations could result from challenges initiated at the FERC by interested parties, by the FERC on its own initiative in a proceeding under Section 206 of the FPA or by a successful application initiated by any of our Regulated Operating Subsidiaries under Section 205 of the FPA. End-use consumers and entities supplying electricity to end-use consumers may attempt to influence government and/or regulators to change the rate setting methodologies that apply to our Regulated Operating Subsidiaries, particularly if rates for delivered electricity increase substantially. Each of our Regulated Operating Subsidiaries is regulated by the FERC as a “public utility” under the FPA and is a transmission owner in MISO or SPP. We cannot predict whether the approved rate methodologies for any of our Regulated Operating Subsidiaries will be changed. In addition, the U.S. Congress periodically considers enacting energy legislation that could shift new responsibilities to the FERC, modify provisions of the FPA or provide the FERC or another entity with increased authority to regulate transmission matters. We cannot predict whether, and to what extent, our Regulated Operating Subsidiaries may be affected by any such changes in federal energy laws, regulations or policies in the future.
If amounts billed for transmission service for our Regulated Operating Subsidiaries’ transmission systems are lower than expected, the timing of collection of our revenues would be delayed.
If amounts billed for transmission service are lower than expected, which could result from lower network load or point-to-point transmission service on our Regulated Operating Subsidiaries’ transmission systems due to weather, a weak economy, changes in the nature or composition of the transmission assets of our Regulated Operating Subsidiaries and surrounding areas, poor transmission quality of neighboring transmission systems, or for any other reason, the timing of the collection of our revenue requirement would likely be delayed until such circumstances are adjusted through the true-up mechanism in our Regulated Operating Subsidiaries’ formula rate templates. The effect of such under-collection would be to reduce the amount of our available cash resources from what we had expected, which may require us to increase our outstanding indebtedness, reducing our available borrowing capacity, and may require us to pay interest at a rate that exceeds the interest to which we are entitled in connection with the operation of the true-up mechanism.
Each of our MISO Regulated Operating Subsidiaries depends on its primary customer for a substantial portion of its revenues, and any material failure by those primary customers to make payments for transmission services would adversely affect our revenues and our ability to service our debt obligations and affect our ability to pay dividends.
ITCTransmission derives a substantial portion of its revenues from the transmission of electricity to Detroit Edison’s local distribution facilities. Detroit Edison accounted for 78.5% of ITCTransmission’s total operating revenues for the

year ended December 31, 2011 and is expected to constitute the majority of ITCTransmission’s revenues for the foreseeable future. Detroit Edison is rated BBB+/stable and Baa1/stable by Standard & Poor’s Ratings Services and Moody’s Investors Services, Inc., respectively. Similarly, Consumers Energy accounted for 79.0% of METC’s total operating revenues for the year ended December 31, 2011 and is expected to constitute the majority of METC’s revenues for the foreseeable future. Consumers Energy is rated BBB-/stable and Baa2/stable by Standard & Poor’s Ratings Services and Moody’s Investors Service, Inc., respectively. Further, IP&L accounted for 78.9% of ITC Midwest’s total operating revenues for the year ended December 31, 2011 and is expected to constitute the majority of ITC Midwest’s revenues for the foreseeable future. IP&L is rated BBB+/stable and A3/negative by Standard & Poor’s Ratings Services and Moody’s Investors Service, Inc., respectively. These percentages of total operating revenues of Detroit Edison, Consumers Energy and IP&L include an estimate for the 2011 revenue accrual and deferrals

that were included in our 2011 operating revenues, but will not be billed to our customers until 2013.We have assumed that the revenues billed to these customers in 2013 would be in the same proportion of the respective percentages of network and regional cost sharing revenues billed to them in 2011.
Any material failure by Detroit Edison, Consumers Energy or IP&L to make payments for transmission services could adversely affect our financial condition and results of operations and our ability to service our debt obligations, and could impact the amount of dividends we pay our stockholders.
A significant amount of the land on which our Regulated Operating Subsidiaries' assets are located is subject to easements, mineral rights and other similar encumbrances. As a result, our Regulated Operating Subsidiaries must comply with the provisions of various easements, mineral rights and other similar encumbrances, which may adversely impact their ability to complete construction projects in a timely manner.
METC does not own the majority of the land on which its electric transmission assets are located. Instead, under the provisions of an Easement Agreement with Consumers Energy, METC pays annual rent of $10.0 million to Consumers Energy in exchange for rights-of-way, leases, fee interests and licenses which allow METC to use the land on which its transmission lines are located. Under the terms of the Easement Agreement, METC's easement rights could be eliminated if METC fails to meet certain requirements, such as paying contractual rent to Consumers Energy in a timely manner. Additionally, a significant amount of the land on which ITCTransmission's, ITC Midwest's and ITC Great Plains' assets are located is subject to easements, mineral rights and other similar encumbrances. As a result, they must comply with the provisions of various easements, mineral rights and other similar encumbrances, which may adversely impact their ability to complete their construction projects in a timely manner.
Our Regulated Operating Subsidiaries contract with third parties to provide services for certain aspects of their businesses. If any of these agreements are terminated, our Regulated Operating Subsidiaries may face a shortage of labor or replacement contractors to provide the services formerly provided by these third parties.
Our Regulated Operating Subsidiaries enter into various agreements and arrangements with third parties to provide services for the operation of certain aspects of their businesses, which, if terminated could result in a shortage of a readily available workforce to provide these services. ITC Midwest and IP&L have entered into the Operations Services Agreement For 34.5 kV Transmission Facilities (the "OSA"), under which IP&L performs certain operations functions for ITC Midwest's 34.5 kV transmission system. The OSA's term is from January 1, 2011 until December 31, 2015, and by its terms will remain in full force and effect from year to year thereafter until terminated by either party upon not less than one year prior written notice to the other party. If the OSA is terminated for any reason or at a time when ITC Midwest is unprepared for such termination, ITC Midwest may face difficulty finding a qualified replacement work force to provide such services, which could have a material adverse effect on its ability to carry on its business and on its results of operations.
Hazards associated with high-voltage electricity transmission may result in suspension of our Regulated Operating Subsidiaries' operations or the imposition of civil or criminal penalties.
The operations of our Regulated Operating Subsidiaries are subject to the usual hazards associated with high-voltage electricity transmission, including explosions, fires, inclement weather, natural disasters, mechanical failure, unscheduled downtime, equipment interruptions, remediation, chemical spills, discharges or releases of toxic or hazardous substances or gases and other environmental risks. The hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment and environmental damage, and may result in suspension of operations and the imposition of civil or criminal penalties. We maintain property and casualty insurance, but we are not fully insured against all potential hazards incident to our business, such as damage to poles, towers and lines or losses caused by outages.
Our Regulated Operating Subsidiaries are subject to environmental regulations and to laws that can give rise to substantial liabilities from environmental contamination.
The operations of our Regulated Operating Subsidiaries are subject to federal, state and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities to investigate or remediate contamination, as well as other liabilities concerning hazardous materials or contamination such as

claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as at properties currently owned or operated by our Regulated Operating Subsidiaries. Such liabilities may arise even where the contamination does not result from noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire share. Environmental requirements generally have become more stringent in recent years, and compliance with those requirements more expensive.

Our Regulated Operating Subsidiaries have incurred expenses in connection with environmental compliance, and we anticipate that each will continue to do so in the future. Failure to comply with the extensive environmental laws and regulations applicable to each could result in significant civil or criminal penalties and remediation costs. Our Regulated Operating Subsidiaries’ assets and operations also involve the use of materials classified as hazardous, toxic, or otherwise dangerous. Some of our Regulated Operating Subsidiaries’ facilities and properties are located near environmentally sensitive areas such as wetlands and habitats of endangered or threatened species. In addition, certain properties in which our Regulated Operating Subsidiaries operate are, or are suspected of being, affected by environmental contamination. Compliance with these laws and regulations, and liabilities concerning contamination or hazardous materials, may adversely affect our costs and, therefore, our business, financial condition and results of operations.

In addition, claims have been made or threatened against electric utilities for bodily injury, disease or other damages allegedly related to exposure to electromagnetic fields associated with electric transmission and distribution lines. We cannot assure you that such claims will not be asserted against us or that, if determined in a manner adverse to our interests, such claims would not have a material adverse effect on our business, financial condition and results of operations.

Our Regulated Operating Subsidiaries are subject to various regulatory requirements, including reliability standards; contract filing requirements; reporting, recordkeeping and accounting requirements; and transaction approval requirements. Violations of these requirements, whether intentional or unintentional, may result in penalties that, under some circumstances, could have a material adverse effect on our financial condition, results of operations and cash flows.

The various regulatory requirements to which we are subject include reliability standards established by the NERC, which acts as the nation’s Electric Reliability Organization approved by the FERC in accordance with Section 215 of the FPA. These standards address operation, planning and security of the bulk power system, including requirements with respect to real-time transmission operations, emergency operations, vegetation management, critical infrastructure protection and personnel training. Failure to comply with these requirements can result in monetary penalties as well as non-monetary sanctions. Monetary penalties vary based on an assigned risk factor for each potential violation, the severity of the violation and various other circumstances, such as whether the violation was intentional or concealed, whether there are repeated violations, the degree of the violator’s cooperation in investigating and remediating the violation and the presence of a compliance program. Penalty amounts range from $1,000 to a maximum of $1.0 million per day, depending on the severity of the violation. Non-monetary sanctions include potential limitations on the violator’s activities or operation and placing the violator on a watchlist for major violators. Despite our best efforts to comply and the implementation of a compliance program intended to ensure reliability, there can be no assurance that violations will not occur that would result in material penalties or sanctions. If any of our Regulated Operating Subsidiaries were to violate the NERC reliability standards, even unintentionally, in any material way, any penalties or sanctions imposed against us could have a material adverse effect on our financial condition, results of operations and cash flows.

The Regulated Operating Subsidiaries are also subject to requirements under Sections 203 and 205 of the FPA for approval of transactions; reporting, recordkeeping and accounting requirements; and for filing contracts related to the provision of jurisdictional services. Under FERC policy, failure to file jurisdictional agreements on a timely basis may result in foregoing the time value of revenues collected under the agreement, but not to the point where a loss would be incurred. The failure to obtain timely approval of transactions subject to FPA Section 203, or to comply with applicable reporting, recordkeeping or accounting requirements under FPA Section 205, could subject us to penalties that could have a material adverse effect on our financial condition, results of operations and cash flows.

Acts of war, terrorist attacks and threats, including cyber attacks or threats, or the escalation of military activity in response to such attacks or otherwise may negatively affect our business, financial condition and cash flows.

Acts of war, terrorist attacks and threats, including cyber attacks or threats, or the escalation of military activity in response to such attacks or otherwise may negatively affect our business, financial condition and cash flows in unpredictable ways, such as increased security measures and disruptions of markets. Strategic targets, such as energy related assets, including, for example, our Regulated Operating Subsidiaries’ transmission facilities and Detroit

Edison's, Consumers Energy's and IP&L's generation and distribution facilities, may be at risk of future terrorist attacks or threats, including cyber attacks or threats. In addition to the increased costs associated with heightened security requirements, such events may have an adverse effect on the economy in general. A lower level of economic activity could result in a decline in energy consumption, which may adversely affect our business, financial condition and cash flows.

Risks Relating to Our Structure and Financial Leverage

ITC Holdings is a holding company with no operations, and unless we receive dividends or other payments from our subsidiaries, we may be unable to pay dividends and fulfill our other cash obligations.

As a holding company with no business operations, ITC Holdings' material assets consist primarily of the stock and membership interests in our Regulated Operating Subsidiaries and our other subsidiaries, deferred tax assets relating primarily to federal income tax NOLs and cash on hand. Our only sources of cash to pay dividends to our stockholders are dividends and other payments received by us from time to time from our Regulated Operating Subsidiaries and our other subsidiaries and the proceeds raised from the sale of our debt and equity securities. Each of our Regulated Operating Subsidiaries, however, is legally distinct from us and has no obligation, contingent or otherwise, to make funds available to us for the payment of dividends to ITC Holdings' stockholders or otherwise. The ability of each of our Regulated Operating Subsidiaries and our other subsidiaries to pay dividends and make other payments to us is subject to, among other things, the availability of funds, after taking into account capital expenditure requirements, the terms of its indebtedness, applicable state laws and regulations of the FERC and the FPA. While we currently intend to continue to pay quarterly dividends on our common stock, we have no obligation to do so. The payment of dividends is within the absolute discretion of our board of directors and will depend on, among other things, our results of operations, working capital requirements, capital expenditure requirements, financial condition, contractual restrictions, anticipated cash needs and other factors that our board of directors deems relevant.

We are highly leveraged and our dependence on debt may limit our ability to fulfill our debt obligations and/or to obtain additional financing.

We are highly leveraged and our consolidated indebtedness consists of various outstanding debt securities and borrowings under various revolving credit agreements. This capital structure can have several important consequences, including, but not limited to, the following:

- If future cash flows are insufficient, we may not be able to make principal or interest payments on our debt obligations, which could result in the occurrence of an event of default under one or more of those debt instruments.
- If future cash flows are insufficient, we may need to incur further indebtedness in order to make the capital expenditures and other expenses or investments planned by us.
- Our indebtedness has the general effect of reducing our flexibility to react to changing business and economic conditions insofar as they affect our financial condition and, therefore, may pose substantial risk to our shareholders.
- A substantial portion of the dividends and payments in lieu of taxes we receive from our Regulated Operating Subsidiaries will be dedicated to the payment of interest on our indebtedness, thereby reducing the funds available for the payment of dividends on our common stock.
- In the event that we are liquidated, our senior or subordinated creditors and the senior or subordinated creditors of our subsidiaries will be entitled to payment in full prior to any distributions to the holders of shares of our common stock.
- We currently have debt instruments outstanding with relatively short remaining maturities. Our ability to secure additional financing prior to or after these facilities mature, if needed, may be substantially restricted by the existing level of our indebtedness and the restrictions contained in our debt instruments. Additionally, the interest rates at which we might secure additional financings may be higher than our currently outstanding debt instruments or higher than forecasted at any point in time.
- Market conditions could affect our access to capital markets, restrict our ability to secure financing to make the capital expenditures and other expenses or investments planned by us and could adversely affect our business, financial condition, cash flows and results of operations.

We may incur substantial indebtedness in the future. The incurrence of additional indebtedness would increase the leverage-related risks described here.

Certain provisions in our debt instruments limit our financial flexibility.

Our debt instruments include senior notes, secured notes, first mortgage bonds and revolving credit agreements containing numerous financial and operating covenants that place significant restrictions on, among other things, our ability to:

- incur additional indebtedness;
- engage in sale and lease-back transactions;
- create liens or other encumbrances;
- enter into mergers, consolidations, liquidations or dissolutions, or sell or otherwise dispose of all or substantially all of our assets;
- create and acquire subsidiaries; and
- pay dividends or make distributions on our and ITCTransmission's capital stock and METC's, ITC Midwest's, and ITC Great Plains' member capital.

The revolving credit agreements, ITC Holdings' senior notes, ITCTransmission's first mortgage bonds, ITC Midwest's first mortgage bonds and METC's senior secured notes require us to meet certain financial ratios, such as maintaining certain debt to capitalization ratios. Our ability to comply with these and other requirements and restrictions may be affected by changes in economic or business conditions, results of operations or other events beyond our control. A failure to comply with the obligations contained in any of our debt instruments could result in acceleration of the related debt and the acceleration of debt under other instruments evidencing indebtedness that may contain cross-acceleration or cross-default provisions.

Adverse changes in our credit ratings may negatively affect us.

Our ability to access capital markets is important to our ability to operate our business. Increased scrutiny of the energy industry and the impact of regulation, as well as changes in our financial performance and unfavorable conditions in the capital markets could result in credit agencies reexamining our credit ratings. A downgrade in our credit ratings could restrict or discontinue our ability to access capital markets at attractive rates and increase our borrowing costs. A rating downgrade could also increase the interest we pay under our revolving credit agreements.

Provisions in our Articles of Incorporation and bylaws, Michigan corporate law and our debt agreements may impede efforts by our shareholders to change the direction or management of our company.

Our Articles of Incorporation and bylaws contain provisions that might enable our management to resist a proposed takeover. These provisions could discourage, delay or prevent a change of control or an acquisition at a price that our shareholders may find attractive. These provisions also may discourage proxy contests and make it more difficult for our shareholders to elect directors and take other corporate actions. The existence of these provisions could limit the price that investors are willing to pay in the future for shares of our common stock. These provisions include:

- a restriction limiting market participants from voting or owning 5% or more of the outstanding shares of our capital stock;
- a requirement that special meetings of our shareholders may be called only by our board of directors, the chairman of our board of directors, our president or the holders of a majority of the shares of our outstanding common stock;
- advance notice requirements for shareholder proposals and nominations; and
- the authority of our board to issue, without shareholder approval, common or preferred stock, including in connection with our implementation of any shareholders rights plan, or “poison pill.”

In addition, our revolving credit agreements provide that a change in a majority of ITC Holdings’ board of directors that is not approved by the current ITC Holdings directors or acquiring beneficial ownership of 35% or more of ITC Holdings outstanding common shares will constitute a default under those agreements.

Provisions in our Articles of Incorporation restrict market participants from voting or owning 5% or more of the outstanding shares of our capital stock.

Certain of our Regulated Operating Subsidiaries have been granted favorable rate treatment by the FERC based on their independence from market participants. The FERC defines a “market participant” to include any person or entity that, either directly or through an affiliate, sells or brokers electricity, or provides ancillary services to an RTO. An affiliate, for these purposes, includes any person or entity that directly or indirectly owns, controls or holds with the power to vote 5% or more of the outstanding voting securities of a market participant. To help ensure that we and our subsidiaries will remain independent of market participants, our Articles of Incorporation impose certain restrictions on the ownership and voting of shares of our capital stock by market participants. In particular, the Articles of Incorporation provide that we are restricted from issuing any shares of capital stock or recording any transfer of shares if the issuance or transfer would cause any market participant, either individually or together with members of its “group” (as defined in SEC beneficial ownership rules), to beneficially own 5% or more of any class or series of our capital stock. Additionally, if a market participant, together with its group members, acquires beneficial ownership of 5% or more of any series of the outstanding shares of our capital stock, such market participant or any shareholder who is a member of a group including a market participant will not be able to vote or direct or control the votes of shares representing 5% or more of any series of our outstanding capital stock. Finally, to the extent a market participant, together with its group members, acquires beneficial ownership of 5% or more of the outstanding shares of any series of our capital stock, our Articles of Incorporation allow our board of directors to redeem any shares of our capital stock so that, after giving effect to the redemption, the market participant, together with its group members, will cease to beneficially own 5% or more of that series of our outstanding capital stock.

Risks Related to the Entergy Transaction

We may be unable to satisfy the conditions or obtain the approvals required to complete the Entergy Transaction or such approvals may contain material restrictions or conditions.

The consummation of the Entergy Transaction is subject to numerous conditions, including (i) consummation of certain transactions and financings contemplated by the merger agreement and the separation agreement (such as the separation of Entergy's transmission business from its distribution business), (ii) the receipt of ITC Holdings shareholder approval, and (iii) the receipt of certain regulatory approvals in a form that will not impose a burdensome condition on us or Entergy (as described in the merger agreement). We can make no assurances that the Entergy Transaction will be consummated on the terms or timeline currently contemplated, or at all. We have and will continue to expend management's time and resources and incur expenses due to legal, advisory and financial services fees related to the Entergy Transaction. Governmental agencies may not approve the Entergy Transaction or may impose conditions to the approval of the Entergy Transaction or require changes to the terms of the Entergy Transaction. Any such conditions or changes could have the effect of delaying completion of the Entergy Transaction, imposing costs on or limiting the revenues of the combined company following the Entergy Transaction or otherwise reducing the anticipated benefits of the Entergy Transaction. Any condition or change which results in a burdensome condition on Entergy's transmission business and/or us under the merger agreement and might cause Entergy and/or us to restructure or terminate the Entergy Transaction.

If completed, the Entergy Transaction may not be successful or achieve its anticipated benefits.

We entered into the Entergy Transaction with the expectation that it would result in various benefits to us and our shareholders. The success of the Entergy Transaction will depend, in part, on the ability of the combined company to realize anticipated growth opportunities. The combined company's success in realizing these growth opportunities, and the timing of this realization, depends in part on the successful integration of our business and operations with the newly merged transmission business and operations. After the Entergy Transaction, we will have significantly more revenue, expenses, assets and employees than we did prior to the Entergy Transaction. We may not successfully or cost-effectively integrate the acquired transmission business and operations into our business and operations. Even if the combined company is able to integrate the transmission businesses and operations successfully, this integration may not result in the realization of the full benefits of the growth opportunities that we currently expect from the Entergy Transaction within the anticipated time frame, or at all.

The merger agreement contains provisions that may discourage other companies from trying to acquire us.

The merger agreement contains provisions that may discourage a third party from submitting a business combination proposal to us prior to the closing of the Entergy Transaction that might result in greater value to ITC Holdings shareholders than the Entergy Transaction. The merger agreement generally prohibits us from soliciting any alternative acquisition proposal, although we may terminate the merger agreement in order to accept an unsolicited alternative transaction proposal that our board of directors determines is superior to the Entergy Transaction. In addition, before our board may withdraw or modify its recommendation or we may terminate the merger agreement to enter into a transaction that our board determines is superior to the Entergy Transaction, Entergy has the opportunity to negotiate with us to modify the terms of the Entergy Transaction in response to any competing acquisition proposals that may be made. If the merger agreement is terminated by us or Entergy in certain limited circumstances, we may be obligated to pay a termination fee to Entergy, which would represent an additional cost for a potential third party seeking a business combination with us.

Failure to complete the Entergy Transaction could adversely affect the market price of ITC Holdings common stock as well as our business, financial condition and results of operations.

If the Entergy Transaction is not completed for any reason, the price of ITC Holdings common stock may decline to the extent that the market price of ITC Holdings common stock reflects positive market assumptions that the Entergy Transaction will be completed and the related benefits will be realized, significant expenses such as legal, advisory and financial services which generally must be paid regardless of whether the Entergy Transaction is completed and the requirement in the merger agreement that, under certain limited circumstances, we must pay Entergy a termination fee.

Investors holding shares of ITC Holdings common stock immediately prior to the completion of the Entergy Transaction will, in the aggregate, have a significantly reduced ownership and voting interest in us after the Entergy Transaction and will exercise less influence over management.

Investors holding shares of ITC Holdings common stock immediately prior to the completion of the Entergy Transaction will, in the aggregate, own a significantly smaller percentage of the combined company immediately after the completion of the Entergy Transaction. Immediately following the completion of the Entergy Transaction, it is expected that Entergy shareholders will hold at least 50.1% of the ITC Holdings common stock and existing ITC Holdings shareholders will hold no more than 49.9% of ITC Holdings common stock. Consequently, ITC Holdings shareholders, collectively, will be able to exercise less influence over the management and policies of the combined company than they will be able to exercise over the management and our policies immediately prior to the completion of the Entergy Transaction.

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We are required to abide by potentially significant restrictions which could limit our ability to undertake certain corporate actions (such as the issuance of ITC Holdings common stock or the undertaking of a merger or consolidation) that otherwise could be advantageous.

The merger agreement and the separation agreement impose certain ongoing restrictions on us to ensure that applicable statutory requirements under the Internal Revenue Code of 1986, as amended, and applicable Treasury regulations are met so that the Entergy Transaction qualifies as tax-free to Entergy and its shareholders. As a result of these restrictions, our ability to engage in certain transactions, such as the redemption of ITC Holdings common stock or the issuance of our equity securities (subject to certain exceptions generally relating to compensation) may be limited until two years and one day following the closing of the Entergy Transaction (excluding the $700 million recapitalization in the form of a special dividend and/or share repurchase to be completed in connection with the Entergy Transaction).

If we take any of an enumerated list of actions and omissions that would cause the Entergy Transaction to become taxable, we generally will be required to bear the cost of any resulting tax liability. If the Entergy Transaction became taxable, Entergy would be expected to recognize a substantial amount of income, which would result in a material amount of taxes. Any such taxes allocated to us would be expected to be material to us, and could cause our business, financial condition and operating results to suffer. These restrictions may reduce our ability to engage in certain business transactions that otherwise might be advantageous to us.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Our Regulated Operating Subsidiaries’ transmission facilities are located in Michigan's Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri and Kansas. Our MISO Regulated Operating Subsidiaries have agreements with other utilities for the joint ownership of specific substations and transmission lines. See Note 15 to the consolidated financial statements.

ITCTransmission owns the assets of a transmission system and related assets, including:

- approximately 2,800 circuit miles of overhead and underground transmission lines rated at voltages of 120 kV to 345 kV;
- approximately 17,700 transmission towers and poles;
- station assets, such as transformers and circuit breakers, at 169 stations and substations which either interconnect ITCTransmission's transmission facilities or connect ITCTransmission’s facilities with generation or distribution facilities owned by others;
- other transmission equipment necessary to safely operate the system (e.g., monitoring and metering equipment);
- warehouses and related equipment;
- associated land held in fee, rights of way and easements;
- an approximately 188,000 square-foot corporate headquarters facility and operations control room in Novi, Michigan, including furniture, fixtures and office equipment; and
- an approximately 40,000 square-foot facility in Ann Arbor, Michigan that includes a back-up operations control room.

ITCTransmission’s First Mortgage Bonds are issued under ITCTransmission’s First Mortgage and Deed of Trust. As a result, the bondholders have the benefit of a first mortgage lien on substantially all of ITCTransmission’s property.

METC owns the assets of a transmission system and related assets, including:

- approximately 5,500 circuit miles of overhead transmission lines rated at voltages of 120 kV to 345 kV;
- approximately 36,500 transmission towers and poles;
- station assets, such as transformers and circuit breakers, at 94 stations and substations which either interconnect METC's transmission facilities or connect METC’s facilities with generation or distribution facilities owned by others;
- other transmission equipment necessary to safely operate the system (e.g., monitoring and metering equipment); and
- warehouses and related equipment.

Amounts borrowed under METC’s revolving credit agreement are secured by a first priority security interest on all of METC’s assets through the issuance of senior secured notes, collateral series, under METC’s first mortgage indenture and the second supplemental indenture thereto.

METC does not own the majority of the land on which its assets are located, but under the provisions of its Easement Agreement with Consumers Energy, METC has an easement to use the land, rights-of-way, leases and licenses in the land on which its transmission lines are located that are held or controlled by Consumers Energy. See “Item 1 Business — Operating Contracts — METC — Amended and Restated Easement Agreement.”

ITC Midwest owns the assets of a transmission system and related assets, including:

- approximately 7,400 miles of transmission lines rated at voltages of 34.5 kV to 345 kV;
- transmission towers and poles;
- station assets, such as transformers and circuit breakers, at approximately 261 stations and substations which either interconnect ITC Midwest’s transmission facilities or connect ITC Midwest’s facilities with generation or distribution facilities owned by others;
- other transmission equipment necessary to safely operate the system (e.g., monitoring and metering equipment);
- warehouses and related equipment; and
- associated land held in fee, rights of way and easements.

ITC Midwest’s First Mortgage Bonds are issued under ITC Midwest’s First Mortgage and Deed of Trust. As a result, the bondholders have the benefit of a first mortgage lien on substantially all of ITC Midwest’s property.

ITC Great Plains owns the assets of two electric transmission substations in Kansas:

- 138 kV Flat Ridge Substation
- 230 kV Elm Creek Substation

As of December 31, 2011, there were no liens or encumbrances on the assets of ITC Great Plains.

The assets of our Regulated Operating Subsidiaries are suitable for electric transmission and adequate for the electricity demand in our service territory. We prioritize capital spending based in part on meeting reliability standards within the industry. This includes replacing and upgrading existing assets as needed.

ITEM 3. LEGAL PROCEEDINGS.

We are involved in certain legal proceedings before various courts, governmental agencies, and mediation panels concerning matters arising in the ordinary course of business. These proceedings include certain contract disputes, regulatory matters and pending judicial matters. We cannot predict the final disposition of such proceedings. We regularly review legal matters and record provisions for claims that are considered probable of loss. The resolution of pending proceedings is not expected to have a material effect on our operations or consolidated financial statements in the period in which they are resolved.

Refer to Notes 4 and 16 to the consolidated financial statements for a description of pending litigation.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Stock Price and Dividends

Our common stock has traded on the NYSE since July 26, 2005 under the symbol “ITC”. Prior to that time, there was no public market for our stock. As of February 17, 2012, there were approximately 580 shareholders of record of our common stock.

The following tables set forth the high and low sales price per share of the common stock for each full quarterly period in 2011 and 2010, as reported on the NYSE and the cash dividends per share paid during the periods indicated.

Year Ended December 31, 2011	High	Low	Dividends
Quarter ended December 31, 2011	$81.90	$70.00	$0.3525
Quarter ended September 30, 2011	$78.89	$64.88	$0.3525
Quarter ended June 30, 2011	$74.67	$67.46	$0.3350
Quarter ended March 31, 2011	$70.28	$61.76	$0.3350

Year Ended December 31, 2010	High	Low	Dividends
Quarter ended December 31, 2010	$63.17	$59.77	$0.3350
Quarter ended September 30, 2010	$63.89	$51.65	$0.3350
Quarter ended June 30, 2010 (a)	$56.66	$21.80	$0.3200
Quarter ended March 31, 2010	$56.04	$50.75	$0.3200

(a) The low sales price per share for the quarter ended June 30, 2010 occurred on May 6, 2010, the day when security prices on the New York Stock Exchange experienced an intraday decline of over 1,000 points within a few minutes before partially recovering. Excluding the sales price per share that occurred on May 6, 2010, the lowest sales price per share for the quarter ended June 30, 2010 was $47.45.

The declaration and payment of dividends is subject to the discretion of ITC Holdings' board of directors and depends on various factors, including our net income, financial condition, cash requirements, future prospects and other factors deemed relevant by ITC Holdings' board of directors. As a holding company with no business operations, ITC Holdings' material assets consist primarily of the common stock or ownership interests in its subsidiaries, deferred tax assets relating primarily to federal income tax NOLs and cash. ITC Holdings' material cash inflows are only from dividends and other payments received from time to time from its subsidiaries and the proceeds raised from the sale of debt and equity securities. ITC Holdings may not be able to access cash generated by its subsidiaries in order to pay dividends to shareholders. The ability of ITC Holdings' subsidiaries to make dividend and other payments to ITC Holdings is subject to the availability of funds after taking into account the subsidiaries' funding requirements, the terms of the subsidiaries' indebtedness, the regulations of the FERC under FPA, and applicable state laws. The debt agreements to which we are parties contain numerous financial covenants that could limit ITC Holdings' ability to pay dividends, as well as covenants that prohibit ITC Holdings from paying dividends if we are in default under our revolving credit facilities. Further, each of our subsidiaries is legally distinct from ITC Holdings and has no obligation, contingent or otherwise, to make funds available to ITC Holdings.

If and when ITC Holdings pays a dividend on its common stock, pursuant to our special bonus plans for executives and certain non-executive employees, amounts equivalent to the dividend may be paid to the special bonus plan participants, if approved by the compensation committee. We currently expect these amounts to be paid upon the declaration of dividends on ITC Holdings' common stock.

The board of directors intends to increase the dividend rate from time to time as necessary to maintain an appropriate dividend payout ratio, subject to prevailing business conditions, applicable restrictions on dividend payments, the availability of capital resources and our investment opportunities.

Prior to the consummation of the Entergy Transaction, we expect to effectuate a $700 million recapitalization, currently anticipated to take the form of a one-time special dividend to ITC Holdings' pre-merger shareholders.

The transfer agent for the common stock is Computershare Trust Company, N.A., P.O. Box 43078 Providence, RI 02940-3078.

In addition, the information contained in the Equity Compensation table under “Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” of this report is incorporated herein by reference.

Stock Repurchases

The following table sets forth, the repurchases of common stock for the quarter ended December 31, 2011:

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Program(2)	Maximum Number or Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2)
October 2011	30,389	$73.05	—	—
November 2011	2,492	72.93	—	—
December 2011	1,253	75.75	—	—
Total	34,134	$73.14	—	—

(1) Shares acquired were delivered to us by employees as payment of tax withholding obligations due to us upon the vesting of restricted stock.

(2) We do not have a publicly announced share repurchase plan.

ITEM 6. SELECTED FINANCIAL DATA.

The selected historical financial data presented below should be read together with our consolidated financial statements and the notes to those statements and “Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations,” included elsewhere in this Form 10-K.

	ITC Holdings and Subsidiaries (a)				
	Year Ended December 31,				
(In thousands, except per share data)	2011	2010	2009	2008	2007
OPERATING REVENUES	$757,397	$696,843	$621,015	$617,877	$426,249
OPERATING EXPENSES					
Operation and maintenance (b)	129,288	126,528	95,730	113,818	81,406
General and administrative (b) (c) (d)	82,790	78,120	69,231	81,296	62,089
Depreciation and amortization (e)	94,981	86,976	85,949	94,769	67,928
Taxes other than income taxes (f)	53,430	48,195	43,905	41,180	33,340
Other operating (income) and expense — net	(844)	(297)	(667)	(809)	(688)
Total operating expenses	359,645	339,522	294,148	330,254	244,075
OPERATING INCOME	397,752	357,321	326,867	287,623	182,174
OTHER EXPENSES (INCOME)					
Interest expense	146,936	142,553	130,209	122,234	81,863
Allowance for equity funds used during construction	(16,699)	(13,412)	(13,203)	(11,610)	(8,145)
Loss on extinguishment of debt	—	—	1,263	—	349
Other income	(2,881)	(2,340)	(2,792)	(3,415)	(3,457)
Other expense	3,962	2,588	2,918	3,944	1,618
Total other expenses (income)	131,318	129,389	118,395	111,153	72,228
INCOME BEFORE INCOME TAXES	266,434	227,932	208,472	176,470	109,946
INCOME TAX PROVISION (f)	94,749	82,254	77,572	67,262	36,650
NET INCOME	$171,685	$145,678	$130,900	$109,208	$73,296
Basic earnings per share	$3.36	$2.89	$2.62	$2.22	$1.72
Diluted earnings per share	$3.31	$2.84	$2.58	$2.18	$1.68
Dividends declared per share	$1.375	$1.310	$1.250	$1.190	$1.130

	ITC Holdings and Subsidiaries (a)				
	As of December 31,				
(In thousands)	2011	2010	2009	2008	2007
BALANCE SHEET DATA:					
Cash and cash equivalents	$58,344	$95,109	$74,853	$58,110	$2,616
Working capital (deficit)	(113,939)	69,338	147,335	1,095	(30,370)
Property, plant and equipment — net	3,415,823	2,872,277	2,542,064	2,304,386	1,960,433
Goodwill	950,163	950,163	950,163	951,319	959,042
Total assets	4,823,366	4,307,873	4,029,716	3,714,565	3,213,297
Long-term debt:					
ITC Holdings	1,459,599	1,459,178	1,458,757	1,327,741	1,687,193
Regulated Operating Subsidiaries	1,185,423	1,037,718	975,641	920,512	556,231
Total long-term debt	2,645,022	2,496,896	2,434,398	2,248,253	2,243,424
Total stockholders' equity	1,258,892	1,117,433	1,011,523	929,063	563,075

	ITC Holdings and Subsidiaries (a)				
	Year Ended December 31,				
(In thousands)	2011	2010	2009	2008	2007
CASH FLOWS DATA:					
Capital expenditures	$556,931	$388,401	$404,514	$401,840	$287,170

(a) ITC Midwest’s results of operations, cash flows and balances are included for the periods presented subsequent to its acquisition of the electric transmission assets of IP&L on December 20, 2007.

(b) The reduction in expenses for 2009 were due, in part, to efforts to mitigate operation and maintenance expenses and general and administrative expenses to offset the impact of lower network load on cash flows and any potential revenue accrual relating to 2009.

(c) During 2011 and 2009, we recognized $2.0 million and $10.0 million, respectively of regulatory assets associated with the development activities of ITC Great Plains as well as certain pre-construction costs for the Kansas V-Plan and KETA projects. Upon initial establishment of these regulatory assets in 2011 and 2009, $1.9 million and $8.0 million, respectively, of general and administrative expenses were reversed of which $1.4 million and $5.9 million were incurred in periods prior to 2011 and 2009, respectively. No initial establishment of regulatory assets occurred in 2010 that resulted in reversal of expenses.

(d) During 2011, we expensed external legal, advisory and financial services fees of $7.0 million relating to the proposed Entergy Transaction recorded within general and administrative expenses of which certain amounts are not expected to be deductible for income tax purposes.

(e) In 2009, the FERC accepted the depreciation studies filed by ITCTransmission and METC that revised their depreciation rates. In 2010, the FERC accepted a depreciation study filed by ITC Midwest which revised its depreciation rates. These changes in accounting estimates resulted in lower composite depreciation rates for ITCTransmission, METC and ITC Midwest primarily due to the revision of asset service lives and cost of removal values. The revised estimate of annual depreciation expense was reflected in 2009 for ITCTransmission and METC and in 2010 for ITC Midwest. See discussion in Note 4 to the consolidated financial statements under “Depreciation Studies.”

(f) The increase in the income tax provision for 2008 compared to 2007 is due in part to the implementation of the Michigan Business Tax, which was in effect from 2008 through 2011 and was accounted for as an income tax, compared to the Michigan Single Business Tax in effect prior to 2008 that was accounted for as a tax other than income tax.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Safe Harbor Statement Under The Private Securities Litigation Reform Act of 1995

Our reports, filings and other public announcements contain certain statements that describe our management’s beliefs concerning future business conditions, plans and prospects, growth opportunities and the outlook for our business and the electric transmission industry based upon information currently available. Such statements are “forward-looking” statements within the meaning of the Private Securities Litigation Reform Act of 1995. Wherever possible, we have identified these forward-looking statements by words such as “will,” “may,” “anticipates,” “believes,” “intends,” “estimates,” “expects,” “projects” and similar phrases. These forward-looking statements are based upon assumptions our management believes are reasonable. Such forward-looking statements are subject to risks and uncertainties which could cause our actual results, performance and achievements to differ materially from those expressed in, or implied by, these statements, including, among others, the risks and uncertainties listed in “Item 1A Risk Factors.”

Because our forward-looking statements are based on estimates and assumptions that are subject to significant business, economic and competitive uncertainties, many of which are beyond our control or are subject to change, actual results could be materially different and any or all of our forward-looking statements may turn out to be wrong. Forward-looking statements speak only as of the date made and can be affected by assumptions we might make or by known or unknown risks and uncertainties. Many factors mentioned in our discussion in this report will be important in determining future results. Consequently, we cannot assure you that our expectations or forecasts expressed in such forward-looking statements will be achieved. Actual future results may vary materially. Except as required by law, we undertake no obligation to publicly update any of our forward-looking or other statements, whether as a result of new information, future events, or otherwise.

Overview

Through our Regulated Operating Subsidiaries, we operate high-voltage systems in Michigan’s Lower Peninsula and portions of Iowa, Minnesota, Illinois, Missouri and Kansas that transmit electricity from generating stations to local distribution facilities connected to our systems. Our business strategy is to operate, maintain and invest in transmission infrastructure in order to enhance system integrity and reliability, to reduce transmission constraints and to allow new generating resources to interconnect to our transmission systems. We also are pursuing development projects not within our existing systems, which are also intended to improve overall grid reliability, reduce transmission constraints and facilitate interconnections of new generating resources, as well as enhance competitive wholesale electricity markets.

As electric transmission utilities with rates regulated by the FERC, our Regulated Operating Subsidiaries earn revenues through tariff rates charged for the use of their electric transmission systems by our customers, which include investor-owned utilities, municipalities, cooperatives, power marketers and alternative energy suppliers. As independent transmission companies, our Regulated Operating Subsidiaries are subject to rate regulation only by the FERC. The rates charged by our Regulated Operating Subsidiaries are established using cost-based formula rate templates, as discussed in “Item 7 Management’s Discussion and

Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism."
Our Regulated Operating Subsidiaries' primary operating responsibilities include maintaining, improving and expanding their transmission systems to meet their customers' ongoing needs, scheduling outages on system elements to allow for maintenance and construction, maintaining appropriate system voltages and monitoring flows over transmission lines and other facilities to ensure physical limits are not exceeded.

Significant recent matters that influenced our financial position and results of operations and cash flows for the year ended December 31, 2011 or may affect future results include:

- Our capital investment of $632.9 million at our Regulated Operating Subsidiaries ($93.0 million, $156.9 million, $269.1 million and $113.9 million at ITCTransmission, METC, ITC Midwest and ITC Great Plains, respectively) for the year ended December 31, 2011, resulting primarily from our focus on improving system reliability and interconnecting new generating resources;
- Debt issuances and borrowings under our revolving credit agreements in 2011 and 2010 to fund capital investment at our Regulated Operating Subsidiaries, resulting in higher interest expense;
- Final recognition of revenues for the ITCTransmission rate freeze revenue deferral in May 2011, as discussed in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism — ITCTransmission's Rate Freeze Revenue Deferral." There was a $6.9 million reduction in network revenues in 2011 compared to 2010 and 2009 relating to the collection of the revenue deferral for the period from only January through May 2011, which resulted in a reduction to after-tax net income of approximately $4.3 million in 2011 compared to 2010 and 2009; and
- The proposed transaction with Entergy in which Entergy will divest and merge its electric transmission business with a wholly-owned subsidiary of ITC Holdings as discussed in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Project Updates and Other Recent Developments." In 2011, we expensed external legal, advisory and financial services fees of $7.0 million and certain internal labor costs of approximately $1.6 million related to the Entergy Transaction recorded within general and administrative expenses. Certain amounts of the external costs are not expected to be deductible for income tax purposes. The external and internal costs related to the Entergy Transaction are not included as components of revenue requirement as they were incurred at ITC Holdings. The transaction fees had a significant effect on net income and earnings per share amounts for the year ended December 31, 2011 and are expected to continue to be significant until the transaction is consummated. Completion of the transaction is anticipated to occur in 2013.

These items are discussed in more detail throughout Management's Discussion and Analysis of Financial Condition and Results of Operations.

Cost-Based Formula Rates with True-Up Mechanism

Our Regulated Operating Subsidiaries calculate their revenue requirements using cost-based formula rate templates and are effective without the need to file rate cases with the FERC, although the rates are subject to legal challenge at the FERC. Under these formula rate templates, our Regulated Operating Subsidiaries recover expenses and earn a return on and recover investments in property, plant and equipment on a current rather than a lagging basis. The formula rate templates utilize forecasted expenses, property, plant and equipment, point-to-point revenues, network load at our MISO Regulated Operating Subsidiaries and other items for the upcoming calendar year to establish projected revenue requirements for each of our Regulated Operating Subsidiaries that are used as the basis for billing for service on their systems from January 1 to December 31 of that year. Our cost-based formula rate templates include a true-up mechanism, whereby our Regulated Operating Subsidiaries compare their actual revenue requirements to their billed revenues for each year to determine any over- or under-collection of revenue. The over- or under-collection typically results from differences between the projected revenue requirement used as the basis for billing and actual revenue requirement at each of our Regulated Operating Subsidiaries, or from differences between actual and projected monthly peak loads at our MISO Regulated Operating Subsidiaries. In the event billed revenues in a given year are more or less than actual revenue requirements, which are calculated primarily using information from that year's FERC Form No. 1, our Regulated Operating Subsidiaries will refund or collect additional revenues, with interest, within a two-year period such that customers pay only the amounts that correspond to actual revenue requirements for that given period. This annual true-up ensures that our Regulated Operating Subsidiaries recover their allowed costs and earn their allowed returns.

ITCTransmission's Rate Freeze Revenue Deferral

ITCTransmission's rate freeze revenue deferral resulted from the difference between the revenue ITCTransmission would have collected under its cost based formula rate and the actual revenue ITCTransmission received for the period from February 28, 2003 through December 31, 2004. The revenue deferral was amortized for ratemaking on a straight-line basis for five years from June 2006 through May 2011 and was included in ITCTransmission's revenue requirement for those periods. Revenues of $11.9

million were recognized in 2010 and 2009 relating to the rate freeze revenue deferral and revenues of $5.0 million were recognized in January through May 2011. The $6.9 million reduction in revenues resulted in a reduction to after-tax net income of approximately $4.3 million in 2011 compared to 2010 and 2009.

Revenue Accruals — Effects of Monthly Peak Loads

For our MISO Regulated Operating Subsidiaries, monthly peak loads are used for billing network revenues, which currently is the largest component of our operating revenues. One of the primary factors that impacts the revenue accrual/deferral at our MISO Regulated Operating Subsidiaries is actual monthly peak loads experienced as compared to those forecasted in establishing the annual network transmission rate. Under their formula rates that contain a true-up mechanism, our Regulated Operating Subsidiaries accrue or defer revenues to the extent that their actual revenue requirement for the reporting period is higher or lower, respectively, than the amounts billed relating to that reporting period. For example, to the extent that amounts billed are less than the revenue requirement for a reporting period, a revenue accrual is recorded for the difference. To the extent that amounts billed are more than the revenue requirement for a reporting period, a revenue deferral is recorded for the difference. Although monthly peak loads do not impact operating revenues recognized, network load affects cash flows from transmission service. The monthly peak load of our MISO Regulated Operating Subsidiaries is affected by many variables, but is generally impacted by weather and economic conditions and is seasonally shaped with higher load in the summer months when cooling demand is higher.

The following table sets forth the monthly peak loads during the last three calendar years.

Monthly Peak Load (in MW) (a)

	2011			2010			2009		
	ITCTransmission	METC	ITC Midwest	ITCTransmission	METC	ITC Midwest	ITCTransmission	METC	ITC Midwest
January	7,326	6,045	2,777	7,255	5,947	2,838	7,314	6,009	2,952
February	7,261	6,058	2,854	6,998	5,800	2,782	7,176	5,818	2,816
March	6,946	5,715	2,520	6,620	5,376	2,517	7,070	5,548	2,696
April	6,483	5,416	2,458	6,501	5,112	2,425	6,761	5,112	2,428
May	10,119	7,239	2,773	9,412	7,240	3,052	6,801	5,296	2,421
June	11,488	8,231	3,403	9,722	7,128	3,207	10,392	8,063	3,385
July	12,321	9,389	3,621	11,451	8,498	3,422	8,751	6,523	2,843
August	11,158	8,538	3,614	11,082	8,422	3,399	9,823	7,181	3,103
September	11,288	7,908	3,456	10,817	7,353	2,804	8,049	5,919	2,596
October	6,642	5,479	2,577	6,725	5,414	2,447	6,456	5,258	2,494
November	7,110	6,095	2,519	6,930	5,734	2,674	6,996	5,778	2,634
December	7,206	6,109	2,752	7,824	6,526	2,928	7,661	6,192	2,856
Total	105,348	82,222	35,324	101,337	78,550	34,495	93,250	72,697	33,224

(a) Our MISO Regulated Operating Subsidiaries are each part of a joint rate zone. The load data presented is for all transmission owners in the respective joint rate zone and is used for billing network revenues. Each of our MISO Regulated Operating Subsidiaries makes up the most significant portion of the rates or revenue requirement billed to network load within their respective joint rate zone.

The following table presents the network transmission rates (per kW/month) for our MISO Regulated Operating Subsidiaries that are relevant to our cash flows since January 1, 2009:

Network Transmission Rate	ITCTransmission	METC	ITC Midwest
January 1, 2009 to December 31, 2009	$2.520	$2.522	$4.162
January 1, 2010 to December 31, 2010	$2.818	$2.370	$6.882
January 1, 2011 to December 31, 2011	$2.495	$2.331	$6.694
January 1, 2012 to December 31, 2012	$2.188	$2.409	$6.797

ITC Great Plains does not receive revenue based on a peak load each month and therefore does not have a seasonal effect on operating cash flows. The SPP tariff applicable to ITC Great Plains is billed ratably each month based on its

annual projected revenue requirement.
Revenue Requirement Calculation
Under their cost-based formula rate templates, each of our Regulated Operating Subsidiaries separately calculates a revenue

requirement based on financial information specific to each company. The calculation of actual revenue requirements for a historic period is used to calculate the amount of network revenues recognized in that period and to calculate the true-up adjustment for that period. The calculation of projected revenue requirements is used to establish the transmission rate used for billing purposes, and follows the same methodology as the calculation of actual revenue requirement. The following steps illustrate the calculation of revenue requirement and the rate-setting methodology under the formula rate template with a true-up mechanism used by our MISO Regulated Operating Subsidiaries. ITC Great Plains follows a similar methodology and uses a FERC-approved return of 12.16% on the common equity portion of its capital structure.

Step One — Establish Projected Rate Base and Calculate Projected Allowed Return

Rate base is projected using the average of the projected month-end balances for the months beginning with December 31 of the current year and ending with December 31 of the upcoming year and consists primarily of projected in-service property, plant and equipment, net of accumulated depreciation, as well as other items.

Projected rate base is multiplied by the projected weighted average cost of capital to determine the projected allowed return on rate base. The weighted average cost of capital is calculated using a projected 13 month average capital structure, the forecasted pre-tax cost of the debt portion of the capital structure and a FERC-approved return of 13.88%, 13.38%, and 12.38% for ITCTransmission, METC, and, ITC Midwest, respectively, on the common equity portion of the capital structure.

Step Two — Calculate Projected Gross Revenue Requirement

The projected gross revenue requirement is calculated beginning with the projected allowed return on rate base, as calculated in Step One above, and adding projected recoverable operating expenses and an allowance for income taxes.

Step Three — Calculate Projected Revenue Requirement

After calculating the projected gross revenue requirement in Step Two above, the projected gross revenue requirement is adjusted for any prior year true-up adjustment discussed in Step Four and is reduced for certain revenues received other than network revenues, such as projected point-to-point, regional cost sharing revenues and rental revenues to arrive at our projected revenue requirement.

Step Four — Calculate True-up Adjustment

The actual transmission revenues billed for 2010 were compared to 2010 actual net revenue requirement which is based primarily on amounts from the completed FERC Form No. 1 for 2010. The true-up adjustment that results from the difference between the actual revenue billed and actual revenue requirement for 2010 was added to the 2012 projected revenue requirement used to determine the 2012 network transmission rate. Interest is also applied to the true-up adjustment.

Illustration of Formula Rate Setting. Set forth below is a simplified illustration of the calculation of ITCTransmission's projected revenue requirement as well as its component of the joint zone network transmission rate for billing purposes under its formula rate setting mechanism for the period from January 1, 2012 through December 31, 2012, that was based primarily upon projections of ITCTransmission's 2012 FERC Form No. 1 data. Amounts below are approximations of the amounts used to establish ITCTransmission's 2012 projected revenue requirement.

Line	Item	Instructions	Amount
1	Projected rate base		$1,028,300,000
2	Multiply by projected 13 month weighted average cost of capital (a)		10.40 %
3	Projected allowed return on rate base	(Line 1 x Line 2)	$106,959,251
4	Projected recoverable operating expenses for 2012		$60,700,000
5	Projected taxes and depreciation and amortization for 2012		$125,900,000
6	Projected gross revenue requirements for 2012	(Line 3 + Line 4 + Line 5)	$293,559,251
7	Less projected revenue credits for 2012		$(46,900,000)
8	Plus/(less) 2010 true-up adjustment		$(28,850,000)
9	Projected revenue requirement for 2012	(Line 6 + Line 7 + Line 8)	$217,809,251
10	Projected average monthly 2012 network load (in kW)		8,295,000
11	Annual component of the joint zone network transmission rate	(Line 9 divided by Line 10)	$26.258
12	Monthly component of the joint zone network transmission rate ($/kW per month)	(Line 11 divided by 12 months)	$2.188

(a) The weighted average cost of capital for purposes of this illustration is calculated as follows:

	Percentage of ITCTransmission's Total Capitalization	Cost of Capital	Weighted Average Cost of Capital
Debt	40.00%	5.18% (Pre-tax) =	2.07%
Equity	60.00%	13.88% (After tax) =	8.33%
	100.00%		10.40%

Capital Investment and Operating Results Trends

We expect a general trend of increases in revenues and earnings for our Regulated Operating Subsidiaries over the long term. The primary factor that is expected to continue to increase our actual revenue requirements in future years is our anticipated capital investment in excess of depreciation as a result of our Regulated Operating Subsidiaries' long-term capital investment programs to improve reliability and interconnect new generating resources, as well as the Entergy Transaction. In addition, our capital investment efforts relating to development initiatives are based on establishing an ongoing pipeline of projects that will position us for long-term growth. Investments in property, plant and equipment, when placed in service upon completion of a capital project, are added to the rate base of our Regulated Operating Subsidiaries. Additionally, construction work in progress balances for our KETA Project and

Kansas V-Plan Project are included in rate base prior to being placed in service, and are expected to result in significant revenues in 2012 compared to 2011.

Our Regulated Operating Subsidiaries strive for high reliability of their systems and to improve accessibility to generation sources of choice, including renewable sources. The Energy Policy Act of 2005 requires the FERC to implement mandatory electric transmission reliability standards to be enforced by an Electric Reliability Organization. Effective June 2007, the FERC approved mandatory adoption of certain reliability standards and approved enforcement actions for violators, including fines of up to $1.0 million per day. The NERC was assigned the responsibility of developing and enforcing these mandatory reliability standards. We continually assess our transmission systems against standards established by the NERC, as well as the standards of applicable regional entities under the NERC that have been delegated certain authority for the purpose of proposing and enforcing reliability standards. We believe we meet the applicable standards in all material respects, although further investment in our transmission systems and an increase in maintenance activities will likely be needed to maintain compliance, improve reliability and address any new standards that may be promulgated.

On October 7, 2010, the NERC issued a recommendation for transmission owners to inspect their transmission systems in order to verify their facility ratings methodology is based on actual field conditions. Each of our MISO Regulated Operating Subsidiaries will undertake a program to assess its system over the next two years as a response to the recommendation. There are likely to be costs associated with the assessment and potential system modifications to mitigate instances where actual field conditions necessitate a facility rating that is unacceptable to the reliable operation of the transmission system. The costs for this mitigation will be determined after the assessment is completed, and the appropriate mitigation is planned and may result in significant operating expenses and/or capital investment. These operating expenses and capital investments would be recovered through higher revenue requirements under the cost-based formula rates of our MISO Regulated Operating Subsidiaries.

We also assess our transmission systems against our own planning criteria that are filed annually with the FERC. Based on our planning studies, we see needs to make capital investments to (1) rebuild existing property, plant and equipment; (2) upgrade the system to address demographic changes that have impacted transmission load and the changing role that transmission plays in meeting the needs of the wholesale market, including accommodating the siting of new generation or to increase import capacity to meet changes in peak electrical demand; (3) relieve congestion in the transmission systems; and (4) achieve state and federal policy goals, such as renewable generation portfolio standards. The following table shows our expected and actual capital investment for each of the Regulated Operating Subsidiaries:

(In millions) Operating Subsidiary	Five-Year Capital Investment Program 2012-2016 (a)	Actual Capital Investment for the Year Ended December 31, 2011 (b)	Forecasted Capital Investment for the Year Ending December 31, 2012
ITCTransmission	$739	$93.0	$ 185 — 210
METC	581	156.9	155 — 180
ITC Midwest	1,128	269.1	295 — 325
ITC Great Plains (c)	343	113.9	95 — 115
Development (d)	1,390	—	—
Total	$4,181	$632.9	$ 730 — 830

(a) The current five-year capital investment program does not include anticipated expenditures related to the Entergy Transaction. The investments in property, plant and equipment would be expected to increase significantly upon closing of that transaction.

(b) Capital investment amounts differ from cash expenditures for property, plant and equipment included in our consolidated statements of cash flows due in part to differences in construction costs incurred compared to cash paid during that period, as well as payments for major equipment inventory that are included in cash expenditures but not included in capital investment until transferred to construction work in progress, among other factors.

(c) ITC Great Plains' investment program includes the KETA Project, Kansas V-Plan Project and Hugo-to-Valliant Project.

(d) Includes development initiatives within the South and North Central Regions.

Investments in property, plant and equipment could vary due to, among other things, the impact of actual loads, forecasted loads, regional economic conditions, weather conditions, union strikes, labor shortages, material and equipment prices and availability, our ability to obtain financing for such expenditures, if necessary, limitations on the amount of construction that can be undertaken on our systems at any one time, regulatory approvals for reasons relating to rate construct, environmental, siting, regional planning, cost recovery or other issues or as a result of legal proceedings and variances between estimated and actual costs of construction contracts awarded. In addition, investments in transmission network upgrades for generator interconnection projects could change from prior estimates significantly due to changes in the MISO queue for generation projects, the generator’s potential failure to meet the various criteria of Attachment FF of the MISO tariff for the project to qualify as a refundable network upgrade, and other factors beyond our control.

Capital Project Updates and Other Recent Developments

Thumb Loop Project

In 2010, we received MISO approval of the Thumb Loop Project located in ITCTransmission's region with a total expected capital investment of $510 million. The Thumb Loop Project consists of a 140-mile, double-circuit 345 kV transmission line and related substations that will serve as the backbone of the transmission system needed to accommodate future wind development projects in the Michigan counties of Tuscola, Huron, Sanilac and St. Clair. Siting application approval was filed with the MPSC in August 2010 and granted by the MPSC in February 2011. Significant capital investments for this project are expected to occur beginning in 2012.

ITC Great Plains

KETA Project

The KETA Project is a 225-mile transmission line that will run between Spearville, Kansas and Axtell, Nebraska. On January 19, 2010, the FERC issued an order approving the novation agreements required by SPP for the designation of the right and obligation to build the Kansas portion of this project to ITC Great Plains by Sunflower Electric Power Corporation and Midwest Energy, Inc. The portion of the transmission line that ITC Great Plains is responsible for constructing will run approximately 174 miles. ITC Great Plains has commenced construction for the first phase of the 345 kV KETA Project, which will run from Spearville, Kansas to Hays, Kansas. In June 2010, ITC Great Plains received siting approval for the second phase of the project, which will run from Hays, Kansas to the Nebraska border and has secured the regulatory approvals required to complete the second phase of the KETA Project. Through December 31, 2011, ITC Great Plains had recorded construction work in progress of $96.9 million for KETA project. We now estimate that the cost for ITC Great Plains’ portion of the KETA Project will be approximately $175 million.

Kansas V-Plan Project

The Kansas V-Plan Project is a 200-mile transmission line that will run between Spearville and Wichita, Kansas. In 2009, the KCC authorized ITC Great Plains to build a portion of the segment from Spearville to Medicine Lodge, Kansas. The portion of the transmission line that ITC Great Plains is responsible for constructing will run approximately 120 miles. The Kansas Corporation Commission approved ITC Great Plains' request for a transmission line siting permit on July 12, 2011. ITC Great Plains has obtained the remaining permits necessary to begin construction of the project. We estimate that ITC Great Plains will invest approximately $300 million to construct its portions of the project.

Regulatory Assets

As of December 31, 2011, we have recorded approximately $13.8 million of regulatory assets for start-up and development expenses incurred by ITC Great Plains, which include certain costs incurred for the KETA Project and the Kansas V-Plan Project prior to construction. In March 2011, we recognized the Kansas V-Plan Project regulatory asset of $2.0 million and corresponding reduction to operating expenses, which resulted in net income of $1.3 million. Subsequent to the initial recognition of the Kansas V-Plan Project regulatory asset in March 2011, we recorded an additional $1.1 million of cost incurred for the Kansas V-Plan Project through December 31, 2011 directly to regulatory assets. Based on ITC Great Plains’ application and the related FERC order, ITC Great Plains will be required to make an additional filing with the FERC under Section 205 of the FPA in order to recover these start-up, development and pre-construction expenses.

Development Bonuses

During 2011 and 2010, we recognized general and administrative expenses of $1.2 million and $1.9 million, respectively, for bonuses for the successful completion of certain regulatory milestones relating to the Kansas V-Plan Project and KETA Project, respectively. It is reasonably possible that future development-related bonuses would be authorized and awarded for these or other development projects.

North Central Region Development

In 2009, we formed Green Power Express and announced the Green Power Express project, which consisted of transmission line segments that would facilitate the movement of power from the Dakotas, Minnesota and Iowa to Midwest load centers that demand energy. After the announcement of the Green Power Express project, MISO undertook RGOS to promote investments in new regional transmission infrastructure and implemented its MVP cost allocation methodology. MISO's RGOS and MVP processes provide a channel for the Green Power Express project, or its underlying segments, to move forward through the planning approval process as MVPs. In December 2011, MISO approved the first portfolio of MVPs identified through the RGOS which includes portions of four MVPs that we intend to build, own and operate. The four MVPs are located in south central Minnesota, portions of Iowa, southwest Wisconsin, and northeast Missouri.

Green Power Express has certain FERC-authorized transmission investment incentives, including the establishment of a regulatory asset for start-up and development costs of Green Power Express and certain pre-construction costs for the project to be recovered pursuant to a future FERC filing. Further, Green Power Express has a FERC-approved formula rate with a return on equity of 12.38% and a capital structure targeting 60% equity and 40% debt. The amount of any future capital expenditures by Green Power Express is currently unknown.

The total development expenses through December 31, 2011 at Green Power Express that may be recoverable through regulatory assets were approximately $5.5 million, which have been recorded to expenses in the periods in which they were incurred. If in a future reporting period it becomes probable that future revenues will result from the authorization to recover these development expenses, we will recognize the regulatory assets. No regulatory assets or construction work in progress for Green Power Express have been recorded as of December 31, 2011.

Entergy Transaction

As of December 4, 2011, Entergy and ITC Holdings executed definitive agreements under which Entergy will divest and then merge its electric transmission business with a wholly-owned subsidiary of ITC Holdings. Entergy's electric transmission business consists of approximately 15,700 miles of interconnected transmission lines at voltages of 69 kV and above and associated substations across its utility service territory in the Mid-South.

The Entergy Transaction would expand our network across the entire middle of the continental United States from the Great Lakes to the Gulf Coast. It will approximately double our asset base, add sizable new markets to our operating and development portfolio, and diversify and enhance growth prospects through an expanded footprint.

The terms of the transaction agreements call for Entergy to divest its electric transmission business to a newly-formed entity, Mid South TransCo LLC ("Mid South TransCo"), and Mid South TransCo's subsidiaries, and distribute the equity interests in Mid South TransCo to Entergy's shareholders in the form of a tax-free spin-off. Mid South TransCo will then merge with a newly-created merger subsidiary of ITC Holdings in an all-stock, Reverse Morris Trust transaction, and will survive the merger as a wholly owned subsidiary of ITC Holdings. Prior to the merger, we expect to effectuate a recapitalization, currently anticipated to take the form of a one-time special dividend of $700 million to ITC Holdings' pre-merger shareholders. The merger will result in shareholders of Entergy receiving approximately 50.1% of the shares of pro forma ITC Holdings in exchange for their shares of Mid South TransCo, with existing shareholders of ITC Holdings owning the remaining approximately 49.9% of the combined company. In addition, Entergy will receive gross cash proceeds of $1.775 billion from indebtedness that will be incurred by Mid South TransCo and its subsidiaries prior to the merger. This indebtedness will be assumed by us.

Completion of the Entergy Transaction is expected in 2013 subject to the satisfaction of certain closing conditions, including the necessary approvals of Entergy's retail regulators, the FERC and ITC Holdings' shareholders. There can be no assurance the Entergy Transaction will be consummated. See "Item 1A Risk Factors — We may be unable to satisfy the conditions or obtain the approvals required to complete the Entergy Transaction or such approvals may contain material restrictions or conditions."

Significant Components of Results of Operations

Revenues

We derive nearly all of our revenues from providing network transmission service, point-to-point transmission service and other related services over our Regulated Operating Subsidiaries' transmission systems to Detroit Edison, Consumers Energy, IP&L and to other entities such as alternative electricity suppliers, power marketers and other wholesale customers that provide electricity to end-use consumers and from transaction-based capacity reservations on our transmission systems. MISO and SPP are responsible for billing and collection of transmission services. As the billing agent for our Regulated Operating Subsidiaries, MISO and SPP collect fees for the use of our transmission systems, invoicing Detroit Edison, Consumers Energy, IP&L and other customers on a monthly basis.

Network Revenues are generated from network customers for their use of our electric transmission systems and consist of both billed network revenues and accrued or deferred revenues as a result of our accounting under our cost-based formula rates that contain a true-up mechanism. Refer to "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies — Revenue Recognition under Cost-Based Formula Rates with True-Up Mechanisms" for a discussion of revenue recognition relating to network revenues. The monthly network revenues billed to customers using the transmission facilities of our MISO Regulated Operating Subsidiaries are the result of a calculation which can be simplified into the following:

(1) multiply the network load measured in kW achieved during the one hour of monthly peak usage for our transmission systems by the appropriate monthly tariff rate by 12 by the number of days in that month; and

(2) divide the result by 365.

Our rates at ITC Great Plains are billed ratably each month based on its annual projected revenue requirement and therefore peak usage does not impact its billed network transmission revenues.

Point-to-Point Revenues consist of revenues generated from a type of transmission service for which the customer pays for transmission capacity reserved along a specified path between two points on an hourly, daily, weekly or monthly basis. Point-to-point revenues also include other components pursuant to schedules under the MISO and SPP transmission tariffs. Point-to-point revenues are a reduction in net revenue requirement for network revenues calculated under our cost-based formula rates.

Regional Cost Sharing Revenues are generated from transmission customers throughout RTO regions for their use of our MISO Regulated Operating Subsidiaries' network upgrade projects that are eligible for regional cost sharing under provisions of the MISO tariff, including MVP projects such as the Thumb Loop Project. Additionally, the KETA Project and Kansas V-Plan Project at ITC Great Plains are eligible for recovery through a region-wide charge under provisions of the SPP tariff. Regional cost sharing revenues consist of both billed regional cost sharing revenues and accrued or deferred revenues as a result of our accounting under our cost-based formula rates that contain a true-up mechanism. The amount of the regional cost sharing revenue accruals (deferrals) is estimated for each reporting period until such time as the regional cost sharing formula rate templates based on actual costs are completed for each of our Regulated Operating Subsidiaries during the following year.

Scheduling, Control and Dispatch Revenues are allocated to our MISO Regulated Operating Subsidiaries by MISO as compensation for the services performed in operating the transmission system. Such services include monitoring of reliability data, current and next day analysis, implementation of emergency procedures and outage coordination and switching. Revenues that are allocated by MISO to our MISO Regulated Operating Subsidiaries relating to these services are determined based on projected expenses incurred but are not subject to a true-up adjustment. In any given year, our MISO Regulated Operating Subsidiaries may earn more or less scheduling, control and dispatch revenues than our actual expenses incurred for control room activities.

Other Revenues consist of rental revenues, easement revenues, revenues relating to utilization of jointly owned lines under our transmission ownership and operating agreements and amounts from providing ancillary services to customers.

Operating Expenses

Operation and Maintenance Expenses consist primarily of the costs of contractors to operate and maintain our transmission systems and costs for our personnel involved in operation and maintenance activities.

Operation expenses include activities related to control area operations, which involve balancing loads and generation and transmission system operations activities, including monitoring the status of our transmission lines and stations. The expenses relating to METC’s Easement Agreement are also recorded within operation expenses.

Maintenance expenses include preventive or planned maintenance, such as vegetation management, tower painting and equipment inspections, as well as reactive maintenance for equipment failures.

General and Administrative Expenses consist primarily of costs for personnel in our legal, information technology, finance, regulatory and human resources organizations, general office expenses and fees for professional services. Professional services are principally composed of outside legal, audit and information technology services. We capitalize to property, plant and equipment portions of certain general and administrative expenses such as compensation, office rent, utilities and information technology.

Depreciation and Amortization Expenses consist primarily of depreciation of property, plant and equipment using the straight-line method of accounting. Additionally, this consists of amortization of various regulatory and intangible assets. We capitalize to property, plant and equipment depreciation expense for vehicles and equipment used in our construction activities.

Taxes other than Income Taxes consist primarily of property taxes and payroll taxes.

Other Operating Income and Expense — Net consists primarily of gains and losses associated with the sale of assets. Additionally, this item consists of income recognized for tax gross-ups received from developers or generators for construction projects as described in Note 2 to the consolidated financial statements under “Generator Interconnection Projects.” The tax gross-up represents the difference between the tax effects of the taxable income associated with the contribution compared to the present value of the tax depreciation deduction of the property constructed using the taxable contribution in aid of construction.

Other items of income or expense

Interest Expense consists primarily of interest on debt at ITC Holdings and our Regulated Operating Subsidiaries. Additionally, the amortization of debt financing expenses is recorded to interest expense. An allowance for borrowed funds used during construction is included in property, plant and equipment accounts and is a reduction to interest expense.

Allowance for Equity Funds Used During Construction (“AFUDC equity”) is recorded as an item of other income and is included in property, plant and equipment accounts. The allowance represents a return on equity at our Regulated Operating Subsidiaries used for construction purposes in accordance with FERC regulations. The capitalization rate applied to the construction work in progress balance is based on the proportion of equity to total capital (which currently includes equity and long-term debt) and the allowed return on equity for our Regulated Operating Subsidiaries.

Income tax provision

Income tax provision consists of federal and state income taxes.

Results of Operations

The following table summarizes historical operating results for the periods indicated:

(In thousands)	Year Ended December 31, 2011	2010	Increase (Decrease)	Percentage Increase (Decrease)	Year ended December 31, 2009	Increase (Decrease)	Percentage Increase (Decrease)
OPERATING REVENUES	$757,397	$696,843	$60,554	8.7%	$621,015	$75,828	12.2%
OPERATING EXPENSES							
Operation and maintenance	129,288	126,528	2,760	2.2%	95,730	30,798	32.2%
General and administrative	82,790	78,120	4,670	6.0%	69,231	8,889	12.8%
Depreciation and amortization	94,981	86,976	8,005	9.2%	85,949	1,027	1.2%
Taxes other than income taxes	53,430	48,195	5,235	10.9%	43,905	4,290	9.8%
Other operating (income) and expenses — net	(844)	(297)	(547)	184.2%	(667)	370	(55.5)%
Total operating expenses	359,645	339,522	20,123	5.9%	294,148	45,374	15.4%
OPERATING INCOME	397,752	357,321	40,431	11.3%	326,867	30,454	9.3%
OTHER EXPENSES (INCOME)							
Interest expense	146,936	142,553	4,383	3.1%	130,209	12,344	9.5%
Allowance for equity funds used during construction	(16,699)	(13,412)	(3,287)	24.5%	(13,203)	(209)	1.6%
Loss on extinguishment of debt	—	—	—	n/a	1,263	(1,263)	(100.0)%
Other income	(2,881)	(2,340)	(541)	23.1%	(2,792)	452	(16.2)%
Other expense	3,962	2,588	1,374	53.1%	2,918	(330)	(11.3)%
Total other expenses (income)	131,318	129,389	1,929	1.5%	118,395	10,994	9.3%
INCOME BEFORE INCOME TAXES	266,434	227,932	38,502	16.9%	208,472	19,460	9.3%
INCOME TAX PROVISION	94,749	82,254	12,495	15.2%	77,572	4,682	6.0%
NET INCOME	$171,685	$145,678	$26,007	17.9%	$130,900	$14,778	11.3%

Operating Revenues

Year ended December 31, 2011 compared to year ended December 31, 2010

The following table sets forth the components of and changes in operating revenues:

(In thousands)	2011 Amount	Percentage	2010 Amount	Percentage	Increase (Decrease)	Percentage Increase (Decrease)
Network revenues	$637,807	84.2%	$595,071	85.4%	$42,736	7.2%
Regional cost sharing revenues	87,304	11.5%	55,638	8.0%	31,666	56.9%
Point-to-point	15,903	2.1%	26,063	3.7%	(10,160)	(39.0)%
Scheduling, control and dispatch	11,583	1.5%	14,525	2.1%	(2,942)	(20.3)%
Other	4,800	0.7%	5,546	0.8%	(746)	(13.5)%
Total	$757,397	100.0%	$696,843	100.0%	$60,554	8.7%

Network revenues increased due primarily to higher net revenue requirements at our Regulated Operating Subsidiaries during the year ended December 31, 2011 as compared to the same period in 2010. Higher net revenue requirements were due primarily to higher rate base associated with higher balances of property, plant and equipment in-service and higher recoverable expenses due to higher operating expenses, partially offset by the final monthly recognition in May 2011 of the ITCTransmission rate freeze revenue deferral described above under "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism — ITCTransmission's Rate Freeze Revenue Deferral."

Regional cost sharing revenues increased due primarily to additional capital projects that have been identified by MISO as eligible for regional cost sharing and placing these projects into service. We expect to continue to receive regional cost sharing revenues and the amounts could increase in the near future, including revenues associated with projects that have been or are expected to be approved for regional cost sharing.

Point-to-point revenues decreased due primarily to a decline in the number of point-to-point reservations.

Scheduling, control and dispatch revenues decreased due primarily to a change in MISO's revenue distribution methodology for these types of revenues in 2011 compared to 2010. The new method was implemented in 2011 to better align the revenues relating to these services with the projected expenses.
Operating revenues for the year ended December 31, 2011 include the network revenue accruals (deferrals) and regional cost sharing revenue accruals (deferrals) as calculated below:

Line	Item	ITCTransmission	METC	ITC Midwest	ITC Great Plains	Total Net Revenue Deferrals
(in thousands)						
1	Estimated net revenue requirement (network revenues recognized) (a)	$ 243,917	$188,577	$203,083	$2,230	
2	Network revenues billed (b)	267,842	198,110	212,778	718	
3	Network revenue accruals (deferrals) (line 1 — line 2)	(23,925)	(9,533)	(9,695)	1,512	
4	Regional cost sharing revenue accruals (deferrals) (c)	(1,637)	(1,237)	4,088	(3,322)	
5	Total net revenue deferrals (line 3 + line 4)	$ (25,562)	$(10,770)	$(5,607)	$(1,810)	$(43,749)

(a) The calculation of net revenue requirement for our Regulated Operating Subsidiaries is described in “Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism — Net Revenue Requirement Calculation.” The amount is estimated for each reporting period until such time as FERC Form No. 1’s are completed for our Regulated Operating Subsidiaries.

(b) Network revenues billed at our MISO Regulated Operating Subsidiaries are calculated based on the joint zone monthly network peak load multiplied by their effective monthly network rates for 2011 of $2.495 per kW/month, $2.331 per kW/month and $6.694 per kW/month applicable to ITCTransmission, METC and ITC Midwest, respectively, adjusted for the actual number of days in the month less amounts recovered or refunded associated with our MISO Regulated Operating Subsidiaries 2009 true-up adjustments. The rates for 2011 include amounts for the collection and refund of the 2009 revenue accruals and deferrals and related accrued interest and the revenues billed in 2011 associated with the 2009 revenue accruals and deferrals are not included in these amounts. Our rates at ITC Great Plains are billed ratably each month based on its annual projected net revenue requirement.

(c) Regional cost sharing revenues are subject to a separate true-up mechanism whereby our Regulated Operating Subsidiaries accrue or defer revenues for any over- or under-recovery. The related revenue accruals or deferrals associated with regional cost sharing revenues are included in the regional cost sharing revenue amounts.

Year ended December 31, 2010 compared to year ended December 31, 2009
The following table sets forth the components of and changes in operating revenues:

(In thousands)	2010 Amount	Percentage	2009 Amount	Percentage	Increase (Decrease)	Percentage Increase (Decrease)
Network revenues	$595,071	85.4 %	$547,279	88.1 %	$47,792	8.7 %
Regional cost sharing revenues	55,638	8.0 %	39,710	6.4 %	15,928	40.1 %
Point-to-point	26,063	3.7 %	17,087	2.8 %	8,976	52.5 %
Scheduling, control and dispatch	14,525	2.1 %	14,578	2.3 %	(53)	(0.4)%
Other	5,546	0.8 %	2,361	0.4 %	3,185	134.9 %
Total	$696,843	100.0 %	$621,015	100.0 %	$75,828	12.2 %

Network revenues increased due primarily to higher net revenue requirements at our Regulated Operating Subsidiaries during the year ended December 31, 2010 as compared to the same period in 2009. Higher net revenue requirements were due primarily to higher rate bases associated with higher balances of property, plant and equipment in-service and higher recoverable expenses due primarily to higher operation and maintenance expenses, partially offset by higher regional cost sharing and point-to-point revenues.

Regional cost sharing revenues increased due primarily to additional capital projects that have been identified by MISO and SPP as eligible for regional cost sharing.

Point-to point revenues increased due primarily to an increase in scheduled transmission flow on our transmission systems.

Other revenues increased due primarily to revenue recognized at METC for utilization of its jointly owned lines under its transmission ownership and operating agreements.

Operating revenues for the year ended December 31, 2010 include the network revenue accruals (deferrals) and regional cost sharing revenue accruals (deferrals) as calculated below:

Line	Item	ITCTransmission	METC	ITC Midwest	ITC Great Plains	Total Net Revenue Deferrals
(In thousands)						
1	Estimated net revenue requirement (network revenues recognized) (a)	$ 238,818	$ 171,259	$ 183,095	$ 1,899	
2	Network revenues billed (b)	267,441	173,710	183,027	1,070	
3	Network revenue accruals (deferrals) (line 1 — line 2)	(28,623)	(2,451)	68	829	
4	Regional cost sharing revenue accruals (deferrals) (c)	(740)	(7,086)	1,464	(745)	
5	Total net revenue accruals (deferrals) (line 3 + line 4)	$ (29,363)	$ (9,537)	$ 1,532	$ 84	$ (37,284)

(a) The calculation of net revenue requirement for our Regulated Operating Subsidiaries is described in "Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations — Cost-Based Formula Rates with True-Up Mechanism — Net Revenue Requirement Calculation." The amount is estimated for each reporting period until such time as FERC Form No. 1's are completed for our Regulated Operating Subsidiaries.

(b) Network revenues billed at our MISO Regulated Operating Subsidiaries were calculated based on the joint zone monthly network peak load multiplied by our effective monthly network rates for 2010. The rates for 2010 include amounts for the collection of the 2008 revenue accruals and the revenues billed in 2010 associated with the 2008 revenue accruals are not included in these amounts. Our rates at ITC Great Plains are billed ratably each month on its annual projected net revenue requirement.

(c) Regional cost sharing revenues are subject to a true-up mechanism whereby our Regulated Operating Subsidiaries accrue or defer revenues for any over- or under-recovery.

Operating Expenses

Operation and maintenance expenses

Year ended December 31, 2011 compared to year ended December 31, 2010

Operation and maintenance expenses increased by $4.8 million due to NERC compliance activities associated with surveying transmission overhead lines, by $3.0 million due to higher vehicles and equipment expenses related to higher fuel costs as well as the age and number of vehicles in the fleet, by $2.6 million due to higher operating and training expenses, and by $2.5 million due to higher costs of helicopter patrolling for infrared and visual inspections of the system and transmission lines. These increases were partially offset by $4.5 million due to lower vegetation management requirements, $3.0 million due to lower substation facility maintenance expenses, and $3.0 million due to reduced structure maintenance primarily caused by reduced tower painting requirement in 2011.

Year ended December 31, 2010 compared to year ended December 31, 2009

Operation and maintenance expenses increased by $15.1 million due to higher vegetation management expenses, by $6.7 million due to higher equipment and structure maintenance, by $4.7 million due to higher tower painting requirements and $4.4 million due to higher substation facility maintenance expenses. The lower operation and maintenance expenses in 2009 were due in part to efforts to mitigate operation and maintenance expenses and general and administrative expenses to offset the impact of lower network load on cash flows and any potential revenue accrual relating to 2009.

General and administrative expenses

Year ended December 31, 2011 compared to year ended December 31, 2010

General and administrative expenses increased by $7.2 million due to higher professional advisory and consulting services primarily related to external legal, advisory and financial services fees related to the Entergy Transaction and by $2.1 million due to higher general business expenses primarily due to increased information technology support. These increases were partially offset by $3.6 million of lower compensation-related expenses and by the reduction of expenses in the first quarter of 2011 of $1.9 million (of which $1.4 million were incurred in periods prior to 2011) in connection with the recognition of the Kansas V-Plan Project regulatory asset.

Year ended December 31, 2010 compared to year ended December 31, 2009

General and administrative expenses increased by $8.0 million due to the reduction of expenses in 2009 in connection with the recognition of regulatory assets relating to development activities of ITC Great Plains as well as certain pre-construction costs for the KETA Project. In addition, general and administrative expenses increased by $11.0 million due to higher compensation and benefit expenses due in part to personnel additions, stock compensation expense and the development bonuses for certain projects at ITC Great Plains. These increases were partially offset by lower professional advisory and consulting services of $4.9 million as well as lower general business expenses of $4.0 million.

Depreciation and amortization expenses

Year ended December 31, 2011 compared to year ended December 31, 2010

Depreciation and amortization expenses increased due primarily to a higher depreciable base resulting from property, plant and equipment additions.

Year ended December 31, 2010 compared to year ended December 31, 2009

Depreciation and amortization expenses at our Regulated Operating Subsidiaries increased due to a higher depreciable rate base resulting from property, plant and equipment additions. This increase was partially offset by the effects of the ITC Midwest depreciation study, which revised ITC Midwest's depreciation rates used to calculate depreciation expense for the 2010 calendar year and resulted in a reduction of depreciation expense of $5.1 million as described in Note 4 to the consolidated financial statements.

Taxes other than income taxes

Year ended December 31, 2011 compared to year ended December 31, 2010

Taxes other than income taxes increased due to higher property tax expenses primarily due to our MISO Regulated Operating Subsidiaries' 2010 capital additions, which are included in the assessments for 2011 personal property taxes.

Year ended December 31, 2010 compared to year ended December 31, 2009

Taxes other than income taxes increased due to higher property tax expenses primarily due to our MISO Regulated Operating Subsidiaries' 2009 capital additions, which are included in the assessments for 2010 personal property taxes.

Other expenses (income)

Year ended December 31, 2011 compared to year ended December 31, 2010

Interest expense increased due primarily to an increase in borrowing levels under our revolving credit agreements.

Year ended December 31, 2010 compared to year ended December 31, 2009

Interest expense increased due primarily to additional interest expense associated with ITC Holdings' $200 million debt issuance in December 2009. This increase was partially offset by the effects of lower borrowing levels and interest rates under our revolving credit agreements.

AFUDC equity increased due to increased property, plant and equipment expenditures and the resulting higher construction work in progress balances during 2010 compared to 2009.

Income Tax Provision

Year ended December 31, 2011 compared to year ended December 31, 2010

Our effective tax rates for the years ended December 31, 2011 and 2010 are 35.6% and 36.1%, respectively. Our effective tax rate differs from our 35% statutory federal income tax rate due primarily to state income taxes as well as the tax effects of AFUDC equity which reduced the effective tax rate. The amount of income tax expense relating to AFUDC equity is recognized as a regulatory asset and not included in the income tax provision. Our Regulated Operating Subsidiaries include taxes payable relating to AFUDC equity in their actual revenue requirements. We recorded a state income tax provision of $3.8 million (net of federal deductibility) during the year ended December 31, 2011, compared to a state income tax provision of $5.9 million (net of federal deductibility) for the year ended December 31, 2010. Included in the state income tax provision recorded during the year ended December 31, 2011 is the effect of the Michigan tax law change as discussed in Note 10, which reduced the income tax provision by $4.6 million.

Year ended December 31, 2010 compared to year ended December 31, 2009

Our effective tax rate for the years ended December 31, 2010 and 2009 are 36.1% and 37.2%, respectively. Our effective rate differs from our 35% statutory federal income tax rate due primarily to state income tax provision of

$5.9 million (net of federal deductibility) recorded during the year ended December 31, 2010 and $8.0 million (net of federal deductibility) recorded during the year ended December 31, 2009, partially offset by the tax effects of AFUDC equity which reduces the effective tax rate. The amount of income tax expense relating to AFUDC equity is recognized as a regulatory asset and not included in the income tax provision. Our Regulated Operating Subsidiaries include taxes payable relating to AFUDC equity in their actual net revenue requirements. Additionally, the income tax provision for the year ended December 31, 2010 has been reduced by $0.7 million for the settlement of an uncertain tax position resulting from the deductibility of transaction costs incurred in connection with the METC acquisition.

Liquidity and Capital Resources

We expect to fund our future capital requirements with cash from operations, our existing cash and cash equivalents and amounts available under our revolving credit agreements (the terms of which are described in Note 8 to the consolidated financial statements). In addition, we may from time to time secure debt and equity funding in the capital markets, although we can provide no assurance that we will be able to obtain financing on favorable terms or at all.

We expect that our capital requirements will arise principally from our need to:

- Fund capital expenditures at our Regulated Operating Subsidiaries and, following the close of the Entergy Transaction, capital expenditures at the subsidiaries of Mid South TransCo. Our plans with regard to property, plant and equipment investments are described in detail above under “Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations — Capital Investment and Operating Results Trends.”
- Fund business development expenses and related capital expenditures. We are pursuing development activities for transmission projects which will continue to result in the incurrence of development expenses and could result in significant capital expenditures.
- Fund working capital requirements.
- Fund our debt service requirements, which are described in detail below under “Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations.” We expect our interest payments to increase each year as a result of the additional debt we expect to incur to fund our capital expenditures.
- Fund dividends to holders of our common stock.
- Fund contributions to our retirement plans, as described in Note 11 to the consolidated financial statements. We expect to contribute up to $11.0 million to these plans in 2012. The impact of the growth in the number of participants in our retirement benefit plans and changes in the requirements of the Pension Protection Act may require contributions to our retirement plans to be higher than we have experienced in the past.

In addition to the expected capital requirements above, any adverse determination relating to the contingencies described in Note 16 to the consolidated financial statements would result in additional capital requirements.

We believe that we have sufficient capital resources to meet our currently anticipated short-term needs. We rely on both internal and external sources of liquidity to provide working capital and to fund capital investments. We expect to continue to utilize our revolving credit agreements and our cash and cash equivalents as needed to meet our short-term cash requirements. During 2011, we entered into new revolving credit agreements at ITC Holdings, ITC Great Plains, ITCTransmission and METC in the amount of $200.0 million, $150.0 million, $100.0 million and $100.0 million, respectively, and an additional revolving credit agreement at ITC Midwest for $75.0 million as described in Note 8 to the consolidated financial statements. As of December 31, 2011, we had consolidated indebtedness under our revolving credit agreements of $201.1 million, with total unused capacity under the agreements of $464.9 million