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Integrated Resource Plan

November 1, 2014

Volume I

NIPSCO 2014 Integrated Resource Plan ("IRP") Overview

Overview of NIPSCO

Northern Indiana Public Service Company ("NIPSCO" or the "Company"), serves approximately 468,000 electric customers across the northern third of Indiana. Resources used to serve our customers include company owned generating facilities with a total Net Demonstrated Capability ("NDC") of 3,405 megawatts ("MW") of coal, natural gas and hydroelectric generation, as well as long-term purchases of wind generation. NIPSCO supplements these resources with short-term purchases of energy from the markets operated by the Midcontinent Independent System Operator, Inc. ("MISO"), of which NIPSCO is a member.

Why does NIPSCO Develop and Submit an IRP?

In the normal course of business NIPSCO plans to reliably and cost-effectively meet its customers' electricity service needs. The purpose of these planning efforts is to develop a resilient and reliable plan to meet the needs of customers in an uncertain and changing environment. As a result, NIPSCO's long-term plan may change over time as conditions change and information is updated.

In addition, according to 170 IAC 4-7-3, 170 IAC 4-7 *et seq.* ("Rule 7"), each public, municipally owned and cooperatively owned utility in the State of Indiana is required to submit an IRP to the Indiana Utility Regulatory Commission ("Commission" or "IURC") every two years. As used in Rule 7, the IRP is the utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs.

The information contained in this document is compiled and presented in accordance with the guidelines for integrated resource planning by an electric utility as outlined in Rule 7, and pending revisions to Rule 7 as defined in Rulemaking RM# 11-07. The rulemaking, an effort to update the Rule 7 based on changing utility industry standards, stems from the Commission Order dated October 14, 2010 in Cause No. 43643. NIPSCO's submission date is consistent with the pending revisions to the rule, and in accordance with the extension granted to affected utilities in the Commission letter dated March 25, 2013.

The 2014 Integrated Resource Plan

In this 2014 IRP, the Company discusses the process, methods, models and assumptions used in the IRP development. The 2014 IRP includes various studies, analyses and reports generated by internal subject matter experts, as well as external consultants and reflects relevant input and comments from customers and interested parties that have participated in the development of the IRP.

This document is organized as follows:

Executive Summary
Summarizes NIPSCO's forward view and driving assumptions, long-term resource requirements and the Short-Term Action Plan summary.

Section 1 - Business Climate
Describes the business climate in which NIPSCO operates and pertinent planning information.

Section 2 - Customer Engagement
Outlines NIPSCO's enhanced customer communications with improved technology, performance measurement, community relations and corporate giving.

Section 3 - Planning Process
Outlines the integrated resource planning process and criteria, and identifies the resource options evaluated for the plan.

Section 4 - Energy and Demand Forecast
Discusses customer electric demand and load characteristics and NIPSCO's customer forecasting methodology.

Section 5 - Existing Resources
Describes NIPSCO's current generating facilities, purchased power agreements, demand-side management programs, and its transmission and distribution system.

Section 6 - Load and Resource Analysis
Evaluates balance between load and existing resources.

Section 7 - Resource Alternatives
Discusses supply and demand-side resource alternatives.

Section 8 - Environmental Considerations
Describes the environmental issues that affect NIPSCO.

Section 9 - Resource Alternatives Analysis
Outlines the integrated resource planning process and potential resource additions.

Section 10 - Transmission and Distribution
Describes NIPSCO's transmission and distribution planning process, criteria, guidelines and assessment for delivering energy services to customers.

Section 11 - 2014 Integrated Resource Plan
Summarizes the long-term plan and the actions recommended in the timeframe of 2014 – 2016.

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Executive Summary

SECTION 1

Business Climate

In This Section

Our goal is to develop a resilient and cost-effective resource portfolio plan that takes into account the changing and uncertain business climate. There are five factors that have the greatest potential to influence customers' energy needs and resource portfolio decisions:

1. *Global and Local Economy*
2. *Environmental Requirements*
3. *Energy Commodity Prices*
4. *Regulatory and Legislative*
5. *Technology*

NIPSCO used these factors to create scenarios and sensitivities that envision robust views of the future.

NIPSCO's aspiration is to become Indiana's Premier Utility. It is an aspiration that firmly drives every aspect of our day-to-day business. This aspiration also drives our efforts to meet customers' long-term energy needs by creating a resource portfolio that is assessed by several key criteria:

- Affordable – Cost-effective, customer-focused options, products, and services
- Reliable - Safe and secure quality service
- Compliant - Continuing to meet all current and future obligations
- Diverse – Reducing potential risks with a diverse resource portfolio

Global and Local Economy

Industrial customers, primarily in steel and oil refining, account for less than one percent of NIPSCO's total customers. These customers, however, make up more than 50 percent of NIPSCO's total energy sales and are among the top production facilities in the United States. These industries have been a mainstay of Northwest Indiana since the late 1800s and require unique energy services. These industries follow economic cycles and are tied to the global economy. As such, NIPSCO's planning assumptions are heavily dependent on its ability to accurately forecast future economic activity.

Other unique customer considerations include the demographics of our service territory. Some residential customers face economic hardships that affect their ability to pay for electric and other utility services.

Environmental Compliance

Environmental regulations impact NIPSCO's customers in that compliance with environmental regulations typically drives significant expenses. A large portion of the next decade's increases in customer costs are expected to be driven by environmental compliance investments. NIPSCO plans for its compliance strategy to focus on the environmental retrofit of existing power plants to maintain the generation fleet's tradition of full environmental compliance. With the completion of Michigan City Generating Station's Unit 12 flue gas desulfurization ("FGD") system in 2015, all of NIPSCO's coal generation fleet will be scrubbed. By 2016, all of NIPSCO's coal generation fleet will be compliant with the United States Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standards ("MATS"). NIPSCO anticipates spending more than $600 million through 2018 to bring existing units into compliance with additional environmental obligations. These environmental investments will start only after due diligence by NIPSCO and approval from the IURC, ensuring our strategy is a cost-effective solution for our customers

There are several recently finalized and emerging rules that are considered in the creation of this IRP. In May 2014, the EPA released its final rule under Section 316(b) of the Clean Water Act ("CWA") that will affect the cooling water intake structure at Bailly Generating Station. In June 2014, the EPA released its draft Clean Power Plan ("CPP") to reduce carbon emissions from power plants under Section 111(d) of the Clean Air Act ("CAA"). NIPSCO has represented the potential impact of the plan in its assumptions, and is assessing the CPP as proposed. In December 2014, the EPA is expected to take final action on coal ash disposal regulations under the Resource Conservation and Recovery Act ("RCRA"). In September 2015, the EPA is expected to issue new effluent limitation guidelines ("ELG") for power plants. All of these rules have been considered in this IRP, with more certainty given to rules and standards with a known implementation date.

Commodity Prices

Delivered fuel costs, energy prices and capacity prices have the potential to influence future portfolio decisions. North American natural gas production has continued to grow. Access to shale gas has improved with drilling technique advancements which have resulted in competitively priced natural gas. Demand for domestic natural gas is expected to grow in the industrial sector, power sector, and for export. Natural gas consumption is expected to accelerate in the power sector as coal generation is retired and renewables continues to be integrated. As the MISO resource portfolio for power generation begins to shift, rising capacity and energy prices are projected. Coal production growth is expected to be limited by competitive fuel prices and declining coal-fired generation. Coal prices are expected to remain fairly flat relative to natural gas prices.

Regulatory and Legislative

Legislative solutions may be part of the answer in helping to balance stakeholder interests. Legislative solutions have been implemented to address energy service providers' infrastructure investment issues. For example, the General Assembly enacted Senate Bill 560 in 2013, which allows utilities to seek incremental rate recovery of costs for projects related to a long-term plan for transmission, distribution and storage system improvements.

Another example involves demand-side management or energy efficiency programs in the state. In 2009, the Commission issued an Order requiring the state's investor-owned electric utilities to achieve an energy savings target of 2 percent of annual sales by 2019, as well as creating a set of core programs to be offered by a single administrator on a statewide basis. In 2014, concerns were raised about the overall expense to implement the programs as well as the impact of these costs on the state's largest industrial customers. Consequently, during the 2014 legislative session, Senate Enrolled Act 340 ("SEA 340") was enacted into law. This Act provides for: 1) an opportunity for the Commission and the General Assembly to examine the mandate and the requirements for a core set of programs to be offered statewide and 2) the ability for customers receiving service at a single site constituting more than one megawatt of electric capacity to opt out of participating in a utility's energy efficiency program. Although the law allows Indiana utilities to continue offering demand-side management ("DSM") programs, the statewide program and the mandates for an energy savings target expire on December 31, 2014. Along with the report required under SEA 340, in March 2014, the Governor issued a letter to the Commission requesting recommendations on DSM and energy efficiency ("EE") policies and programs, so that they may serve as a framework for potential legislation in the upcoming 2015 session of the Indiana General Assembly. On September 23, 2014, the Commission presented its findings to the Interim Study Committee on Energy, Utilities and Telecommunications and on October 9, 2014, the Commission submitted its responses to the Governor's request. Both reports provided information about and recommendations for appropriate EE goals for Indiana, reflecting an examination of the overall effectiveness of current DSM programs in the state; issues that may improve current DSM programs; thorough benefit-cost analysis of the cost impact to ratepayers of possible DSM programs; and an allowance for an opt-out whereby large electricity consumers can decide not to participate in a DSM program.

Technology

NIPSCO takes into account the impact of new technologies, standards and regulations on customers' energy usage and patterns. NIPSCO considers a broad array of portfolio options including base load, intermediate, peaking, intermittent and end user operations. NIPSCO continues to monitor technology development, including, but not limited to, advancements in solar, off-shore wind, and high voltage direct current transmission lines.

NIPSCO considers the following criteria when assessing options:

- Energy source availability
- Technical feasibility
- Commercial availability
- Economic attractiveness
- Environmental compatibility

Scenarios

Scenarios, by envisioning a range of potential futures, help to avoid a single view of the future or simply looking at the future by extrapolating from the past. In addition, scenarios provide a framework to evaluate future investments, strategies and business decisions. To this end, NIPSCO has developed two plausible and robust scenarios: a) Slow Economic Improvement and b) Aggressive Environmental Regulations. NIPSCO's scenarios utilized a broad base of internally consistent inputs and assumptions from external and internal subject matter experts while focusing on a range of outcomes for the most significant and uncertain market drivers.

While the most significant drivers established the scenario's direction, the range of each scenario is further expanded and explored through sensitivity analysis. Sensitivity analysis changes one variable, and the applicable correlated variables, in a scenario to see what would happen to the present value of revenue requirement for a portfolio. As discussed at all of the stakeholder meetings, NIPSCO looked at a number of sensitivities around the 2014 scenarios including various levels of load growth, commodity prices, carbon and cost escalation.

SECTION 2

Customer Engagement

In This Section

- *We continue to enhance communications and customer engagement to build relationships with our stakeholders*
- *NIPSCO supports the communities we serve and is an economic development leader*

Enhancing Customer Engagement

NIPSCO continues to enhance communications and customer engagement to build and maintain relationships with our customers. We are proud to be an active part of the communities we serve in northern Indiana and are committed to delivering on our commitments by focusing on planning, collaborative stakeholder engagement, execution, and transparent measurement and reporting.

Collaborative Stakeholder Engagement

NIPSCO engages stakeholders through formalized communications processes, as well as on-going informal discussions. From the public open house meetings that introduced the new Greentown-Reynolds transmission line to area residents, to the collaborative settlement achieved for the next phase of the feed-in tariff ("FIT"), communications between stakeholders continues to establish common ground and resolve differences through collaboration.

IRP Public Advisory Process

This stakeholder engagement focus extends to our long-term planning process and the development of the IRP. NIPSCO implemented a process to enhance public involvement through individual and joint stakeholder meetings to provide information and solicit relevant input for consideration in the development of the 2014 IRP. First, NIPSCO shared information about our public advisory process, modeling methods, assumptions and inputs, treatment of risk and uncertainty, and an overview of our preliminary analysis. As part of the process, stakeholders provided feedback and NIPSCO modeled requested sensitivity and breakpoint analysis using assumptions provided by the various stakeholders. After additional analysis was completed, NIPSCO met with individual stakeholders to respond to comments and questions, and to discuss results of the analysis, gather feedback, and conduct additional analysis as requested. Next, NIPSCO held a joint stakeholder meeting to discuss follow-up responses, share results of the supplemental analysis, present our preferred portfolio and gather feedback. After further analysis was completed, NIPSCO again met with individual stakeholders to respond to comments, discuss results, and gather feedback. Both of the joint stakeholder meetings included on-line webinar access for online stakeholders. NIPSCO shared the results of all requested analysis with stakeholders. Finally, NIPSCO conducted a third joint stakeholder meeting (TouchPoint webinar) to provide a status update regarding the development of our plan, summarize analysis conducted, and gather feedback. Consistent with NIPSCO's ongoing business planning process, NIPSCO will to continue the stakeholder outreach and communications process to ensure ongoing communication. We have established and will maintain the IRP web page with current information on the IRP and welcome the opportunity to meet with stakeholders to discuss key issues and consider varied perspectives. Table 2-1 summarizes the activities surrounding the public engagement process that was implemented in January 2014 for the 2014 IRP. Presentations prepared for discussions with stakeholders are contained in Appendix E.

Table 2-1
NIPSCO IRP Public Advisory Process Statistics

Activity	Number
Public Stakeholder Meetings Conducted	2
Public Stakeholder TouchPoint Webinars Conducted	1
Stakeholder Groups Participated	16
One-on-One Meetings Conducted	18
Case Studies Performed for Stakeholders	47

Fostering Community Partnerships - Community Advisory Panels ("CAPs")

There are many avenues used by NIPSCO to engage with customers and stakeholders. One example is the use of CAPs which serve as a forum for education and feedback in the IRP process. The CAPs also serve as a forum to discuss new company initiatives and programs as well as to facilitate feedback regarding service and other NIPSCO-related matters in their communities. NIPSCO has established five regions across the Company's footprint for the CAPs; which are comprised of individual customers as well as local government and community leaders representing a broad cross-section of NIPSCO customers. NIPSCO senior management meets with each of the regional CAPs three times annually to share the company's strategic direction and to ask CAP members for their insights on emerging issues.

Community Support

Supporting Job Growth and Economic Development

NIPSCO is a leader in driving local and statewide economic development opportunities and invests more than $1 million annually on economic development initiatives through established partnerships with local communities, the State, and regional economic development organizations across its service territory. . In addition, NIPSCO's Economic Development Rider ("EDR") tariff offers discounts on existing tariff services for qualifying economic development projects that bring in new jobs and investment from outside the territory. When coupled with local and state incentives, a powerful package is created with often positive results.

Through streamlining the process for companies moving to the area, and helping existing businesses expand, NIPSCO has successfully helped communities grow with the attraction of new jobs and will continue to do so in the future. In recent months, qualifying business expansions for two companies resulted in the creation of nearly 500 jobs

Two recent projects utilizing the EDR will join our top 20 industrial list based upon the size of their significant electric loads. In both cases, the EDR offering was an important part of the overall incentive package. In 2012, working together with state and local partners helped to land Magnetation, LLC in Reynolds, Indiana. This $350 million iron ore pellet plant will create approximately 100 new jobs by 2015. The new facility will produce high-quality iron ore pellets, a critical raw material in the steelmaking process. In 2013, Pratt Paper (Indiana), LLC announced a major investment of $260 million in Valparaiso, Indiana to construct a new 100 percent recycled paper facility adjacent to its existing box-making plant creating up to 137 new jobs by 2018. When it reaches its full capacity, the new mill will produce an increased 360,000 tons of recycled paper each year.

Although NIPSCO's resource plans focus on maintaining and developing resources in NIPSCO's service territory, the transmission and distribution system is designed to provide all customers with reliable energy services. In addition to efforts related to bringing new jobs to the service territory for NIPSCO facility construction, NIPSCO has a focused effort, tapping local, Indiana-based resources first as it relates to building and construction support, supplies and other specialized service needs.

Corporate Citizenship

Recognizing the importance of being a good corporate citizen, NIPSCO directly invests more than $1.5 million annually to support local organizations and efforts that help improve the overall quality of life across the service area. In addition to this annual commitment, special projects have included:

- In 2013 and 2014, NiSource, its employees, vendors, family and friends contributed $100,000 to the Red Cross, $125,000 for Toys for Tots, $130,000 to Supporting our Veterans, and $15,000 for the Special Olympics.
- NIPSCO employees at all levels of the organization actively volunteer their time and effort within local communities. Many employees take leadership positions on local boards that help drive economic development, support those in need and make northern Indiana a better place to live.
- NIPSCO participates in customer outreach throughout the service territory promoting new energy efficiency programs and convenient access to Company representatives to ask questions and to provide feedback and suggestions.

Supplier Diversity and Community Economic Inclusion

NIPSCO continually seeks to improve and expand supplier diversity and community economic inclusion across our business activities. Central to our vision is a supplier diversity program that strengthens and widens the playing field for qualified suppliers that are typically underutilized in the supply chain of a large corporation. Building relationships with diverse suppliers helps us engage a wider range of suppliers, which means we harness innovative ideas and processes, gain a competitive advantage and assist in building community infrastructure through employment and training. We are committed to offering diverse suppliers an opportunity to succeed. It affirms our commitment to inclusion and diversity, supports our business objectives and benefits our communities. Key objectives for this program include:

- Assure an engaged, aligned, and transparent sustainability approach.
- Proactively align opportunities across business units with suppliers.
- Develop tools and processes that connect procurement with diverse suppliers.
- Drive processes to attain performance measures for supplier diversity activities.
- Collaborate with public/private advocacy organizations and utility forums to influence behavior in support of the program.
- Implement a communication plan to increase internal and external awareness.

Delivering Outstanding Customer Service

Through customer input, learning from top-performing utilities in the customer service category and other research efforts, NIPSCO has forged a strong commitment to improving service to its customers. NIPSCO strives to be a trusted energy adviser for customers, while developing more convenient options to manage bills, receive helpful information and conduct business. NIPSCO has also been focused on providing more convenient ways for customers to connect with the Company through the web, enhancements to our Interactive Voice Response ("IVR") system, and a mobile platform whereby customers can view and pay their bills, report gas leaks and power outages as well as view the outage map for details regarding cause and estimated time of restoration. Since 2013, NIPSCO has had the lowest level of justified complaints among the large utilities in Indiana and ranks in the first quartile of utilities across North America with regards to Average Speed of Answer and Abandonment Rate.

Surveys

Customer feedback is important to us and informs what we do in customer engagement, support, and customer service offerings. NIPSCO conducted surveys after its three joint stakeholder public advisory meetings to assess the value and effectiveness of the process, as well as to identify potential future improvements. NIPSCO also surveys customers to measure customer satisfaction with the call center and interactions with field personnel, as well as the on-line experience such as Mobile, IVR and Web. Customer surveys are also used to capture specific customer issues, and to get immediate feedback on the quality of customer service. NIPSCO uses the results of these surveys, as well as the information obtained through the J.D. Power surveys, to identify potential ways to improve the overall customer experience including training and development for customer service representatives ("CSRs") and field personnel.

Enhancing Customer Alternatives

FIT and Net Metering Tariff

NIPSCO offers both a feed-in and net metering program aimed at promoting further renewable generation opportunities in northern Indiana and responding to customers' interest in powering their homes and businesses with renewable energy projects. NIPSCO collaborated with the Indiana Office of Utility Consumer Counselor, the Hoosier Chapter of the Sierra Club, Citizen's Action Coalition, Inc. ("CAC") Indiana Distributed Energy Alliance, Inc. ("IndianaDG") and Bio Town Ag regarding the expansion of the Company's ability to acquire or purchase customer-generated electricity from renewable energy.

The FIT, which is currently before the Commission for updates and renewal in IURC Cause No. 44393, allows small independent power producers of renewable energy, and residential customers with renewable energy resources, to offset their electric consumption costs by selling to NIPSCO power generated via these renewable resources. It allows NIPSCO access to a diverse mix of small capacity renewable resources to include new wind, solar, biomass, and hydroelectric technologies. In addition to contributing to environmental sustainability, the overarching benefit of the proposed FIT is for NIPSCO to gather information about smaller projects and how and when our customers choose to elect such options and how renewable options operate in our service territory. NIPSCO also offers a net metering program, which allows all classes of retail customers who generate renewable electricity to net their production against their NIPSCO bills.

Electric Vehicle Tariff

NIPSCO is wrapping up the third year of a three-year pilot for electric vehicles as approved by the Commission in February 2012 in IURC Cause No. 44016. Through July 31, 2014, 138 home chargers have been installed, with 11 more working through the process. In addition, NIPSCO has installed 13 chargers on its property and 8 public chargers in the service territory. The pilot runs through January 31, 2015.

Green Power

NIPSCO's Green Power Program is a voluntary program that allows customers to designate a portion or all of their monthly electric usage to be attributable to power generated by renewable energy sources, such as wind power. Customers can enroll online, through the IVR system or through a CSR.

SECTION 3

Planning Process

In This Section

Planning is part of NIPSCO's ongoing business process. NIPSCO's 2014 IRP reflects the Company's long-term plan based on information available at the time.

- *The goal of NIPSCO's 2014 IRP is to identify resource options that reliably and cost-effectively meet customers' energy needs.*
- *Internal and external experts identified key assumptions, including operating parameters, customer needs, resource technologies, environmental regulations, economic conditions, and commodity markets.*
- *New to the 2014 IRP was increased involvement and discussion with key public stakeholders that represented a diverse set of viewpoints of our customer base.*

NIPSCO's Planning Process

Long-term planning is already engrained in NIPSCO business strategy, occurring on a continuous cycle. The IRP represents a snapshot in time of the plan of NIPSCO's future plans.

Description of the IRP Process

NIPSCO developed its 2014 IRP by modeling projected customer electric load and the resource options that could be used to meet that load. The goal is to develop a long-term strategic plan that ensures NIPSCO will continue to provide reliable, reasonable-cost service to its customers.

The Long-Term Strategic Plan identifies customer and resource needs over a 20-year planning horizon, and recommends a potential resource portfolio to meet customer needs. A Short-Term Action Plan identifies the steps NIPSCO will take during 2015 and 2016 to implement the strategic plan. The plan provides for compliance with applicable mandates and policies, and uses a balanced approach to manage cost, risk, uncertainty and reliability elements.

New to the IRP process this year was the opportunity for increased public involvement, which included public meetings and one-on-one meetings. This public advisory process is described in more detail in Section 2 - Customer Engagement.

Creating NIPSCO's 2014 IRP was an iterative process, using both internal and external resources to accomplish the tasks necessary to complete the process, which included:

- Collecting data needed for the planning process, including operating parameters, customer demand forecast, resource technologies, environmental compliance plan, economic conditions, and commodity markets.
- Identifying demand-side and supply-side resource options (market-based, self-build and renewable) resources.
- Evaluating resources, considering environmental externalities.
- Selecting the best options to create an integrated, effective, and responsive plan.

NIPSCO recognizes planning for future economic and environmental are often difficult to predict with accuracy. Based on the uncertainty analyses, the 2014 IRP addresses the most likely contingencies. The options were integrated resulting in the optimal long-term plan. The Short-Term Action Plan was developed to identify implementation steps in the first two years. After developing the Short-Term Action Plan, NIPSCO will continue the planning process, by monitoring changes in elements of the plan.

In summary, the 2014 IRP process takes a myriad of resource options through various screening and detailed analyses, scenarios and sensitivities to methodically funnel down the resource options until a combination of feasible and economic resource options are reached. This combination of resources reliably meets the anticipated customer needs, at the lowest reasonable cost while maintaining flexibility. Because NIPSCO's planning process is part of the ongoing business process, new information is analyzed and incorporated as it becomes available.

The NIPSCO IRP Team consisted of experts from key functional areas within NIPSCO and its affiliate NiSource Corporate Services Company. Additionally, the following energy and engineering consultants listed below provided input to the development of the 2014 IRP:

- Applied Energy Group, Inc. developed DSM measures inputs for a long-term DSM forecast
  500 Ygnacio Valley Road, Suite 450, Walnut Creek, California 94596
- Sargent & Lundy performed the engineering study
  55 East Monroe Street, Chicago, Illinois 60603
- Ventyx, L.L.C. provided consulting services for the IRP preparation and evaluation
  400 Perimeter Center Terrace, Suite 500, Atlanta, Georgia 30346
- IHS Global Insight provided forecasts of independent variables for load forecasting process
  24 Hartwell Avenue, Lexington, Massachusetts 02421
- James Marchetti, Inc. provided Environmental Compliance Planning assistance
  P.O. Box 36, Great Barrington, Massachusetts 01230
- PIRA Energy Group provided the environmental assumptions for NO_x, SO_2 and CO_2 and correlated long-term commodity assumptions
  3 Park Avenue, 26th Floor, New York, New York 10016
- Telvent DTN, Inc. provided hourly weather data for three Indiana weather stations
  9110 West Dodge Road, Omaha, Nebraska 68114
- Morgan Marketing Partners provided assistance with modeling DSM programs in DSMore™
  6205 Davenport Drive, Madison, Wisconsin 53711
- Itron, Inc. provided historical and forecasted end use data
  2111 North Molter Road, Liberty Lake, Washington 99019

Additional resources were provided by representatives of the public stakeholder group.

- National Wildlife Federation, Offshore Wind in the Atlantic
  11100 Wildlife Center Drive, Reston, Virginia 20190
- Electric Power Research Institute, Valuation of Renewable and Distributed Resources: Implications for the Integrated Resource Planning
  3420 Hillview Avenue, Palo Alto, California 94304
- Synapse Energy Economics, Inc., 2013 Carbon Dioxide Price Forecast
  485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139
- Clean Line Energy Partners LLC, provided project development information for the delivery of high capacity factor wind power to distant load centers via long-distance transmission lines
  1001 McKinney, Suite 700, Houston, Texas 77002

Presentation materials from the 2012 - 2014 IURC IRP Contemporary Issues Technical Conferences were also considered.

SECTION 4

Energy and Demand Forecast

In This Section

- *NIPSCO expects total energy consumption will grow at a rate of less than 0.5 percent annually over the next 20 years.*
- *NIPSCO's on-going implementation of energy efficiency programs helps in reducing energy consumption among commercial, industrial, and residential end users.*
- *Peak demand is expected to grow from 3,208 MW in 2014 to 3,574 MW by 2035.*

Discussion of Load

NIPSCO has a high proportion of manufacturing and industrial load on its system that affects both demand and resource planning, which is highly variable and difficult to forecast. Understanding the demand characteristics of NIPSCO's customers is important to establishing the demand and energy forecast.

Unique Customer Base

NIPSCO works to achieve a balance to meet the needs of all of its customers when developing and proposing solutions to issues facing the businesses and residents of northern Indiana. NIPSCO's customer base ranges from very large industrial customers, various large, medium and small commercial and business customers, to more than 375,000 residential customers located in urban, suburban and rural settings. Each customer group has its own set of specific attributes and needs, which provides NIPSCO with its unique customer profile.

For example, industrial customers, primarily in steel and oil refining, account for less than one percent of NIPSCO's total customers. These customers, however, make up more than 50 percent of NIPSCO's total energy sales and are among the top production facilities in the United States. These industries have been a mainstay of Northwest Indiana since the late 1800s and require unique energy services. While operations consume large amounts of energy, their consumption can vary widely on short notice. These industries follow economic cycles and are tied to the global economy. As such, NIPSCO's planning assumptions are heavily dependent on its ability to accurately forecast future economic activity.

Other unique customer considerations include the demographics of our service territory. Some residential customers face economic hardships that affect their ability to pay for electric and other utility services. The need for a cost-effective plan is of particular importance to this segment of customers.

Uncertainty of Industrial Demand

As stated, approximately 50 percent of NIPSCO's energy sales are attributed to the industrial class which creates complexity in forecasting electric demand. Because the level of industrial consumption on NIPSCO's system is greater than all other rate classes, industrial loads are capable of creating swings in demand throughout any given hour, day or week. Industrial consumption (primarily steel manufacturing) is generally not weather sensitive, but rather is more likely to be responsive to business cycles and trends. Individual operations inside our customers' steel mills can swing load by more than 80 MW almost instantly. Industrial consumption is highly dependent upon transmission, distribution and energy delivery reliability. That is, industrial loads often rely on equipment that is sensitive to voltage fluctuation or that requires considerable electricity flow to restart after maintenance or shut-down.

There are also several key characteristics underlying NIPSCO's industrial forecast.

- Volatility of the industrial load is capable of impacting the demand forecast because large industrial users can vary consumption by 20 percent or more within a one-hour period, depending on operating schedules, production upsets, and equipment availability. If industrial users use less or more than predicted, or operate with greater or more frequent load swings, the forecast may not be representative of future actual events.
- If one large industrial customer severely downsizes or shutters its operations, this may result in cost shifts. All of our steel-related energy demand is driven by three steel manufacturing customers, a challenge which is unique to NIPSCO among Indiana utilities.
- Steel production levels vary. In the latest recession, from 2007-2010, steel industry energy consumption dropped more than 30 percent.
- The future of carbon or greenhouse gas ("GHG") regulation is uncertain.

Methodology

The 2014 IRP electric energy and peak demand forecast model uses an econometric approach to forecast long-term electric energy sales and peak hour demands. The forecast employs data representing service area demographics and economic data, saturation and efficiency information, electric energy sales by class, price of energy and average monthly and peak hour weather. Residential consumption is related to end uses and efficiencies and real per capita income. Commercial activity is captured with actual county retail sales. Prices for typical electric bills are used in both the residential and commercial econometric models to measure customer behavior in reaction to changing price.

In creating the NIPSCO Forecast for the 2014 IRP, individual forecast models were developed and validated for residential and commercial customer counts and energy sales for residential, commercial industrial, street lighting, public authority, railroad, and company use. There is also a model for 60-minute electric peak demand.

Description of Energy Forecast

The Residential Energy Forecast Model is calculated working with NIPSCO's New Business team, using a residential customer model and an average residential use per customer model. Average residential use per customer projections are multiplied by the total residential customer forecast to generate the total residential energy forecast. The residential use per customer model is a function of appliance saturations and efficiencies as defined in an end use variable supplied by Itron, Inc., real per capita income, and the actual price of electricity. Other forecast considerations integrated into the residential forecast model include residential customer counts, cooling degree days ("CDD") and heating degree days ("HDD"). The residential customer count is a function of a three-year outlook for new construction provided by NIPSCO's New Business team and is developed using a grassroots approach. This grassroots approach includes conducting interviews with real estate developers and builders; thus assuring that short-term housing market intelligence is included in the forecast. The longer term customer outlook is modeled as a function of housing starts and is adjusted for customer attrition applied at an average historic rate. Total residential customers are calculated by incorporating the new customer outlook, existing customers and the historic attrition rate.

The Commercial Energy Forecast Model is estimated using a total commercial energy usage model. Commercial energy consumption is a function of the commercial customer count, real county retail sales, energy price and CDD. As with residential, the initial three-year outlook for commercial customers is provided by NIPSCO's New Business team. The longer term view is modeled as a function of local population and actual gross county product. The commercial customer count forecast also reflects a historical attrition rate.

The Industrial Energy Forecast Model forecasts the expected level of industrial energy sales in NIPSCO's service territory. Accordingly, the industrial energy forecast model contains individual forecasts for the major industrial account customers.

To obtain information specifically relevant to the creation of the industrial sales forecast, NIPSCO makes contact with each of its Major Industrial account customers and discusses each customer's individual business, economic and strategic objectives. The goals, plans and concerns outlined in these one-on-one discussions form the basis of a forecast recommendation for each customer. The resulting forecast for the group, referred to as the Major Industrial Forecast, includes details concerning the outlook for steel producers and related industries in northwest Indiana. Importantly for the development of the NIPSCO Forecast for the 2014 IRP, this forecast integrates the actual economic and business projection of the customer and their consumption related to each of their major industrial production sites in NIPSCO's service territory.

The industrial sales forecast model also integrates a sales forecast for the remaining industrial accounts (identified as Other Industrial). The Other Industrial forecast includes analysis of historic usage patterns, ongoing discussions with industrial customers and industry related intelligence.

The Street-Lighting, Public Authority, Railroads, Company Use and Losses forecasts are based on both current levels and anticipated trends.

The 60-Minute Electric Peak Demand Model calculates with a regression model using energy sales by class, cooling degree hours (summer) or heating degree hours (winter) at peak hour, and relative humidity at peak hour.

Customer Self-Generation assumes that most of NIPSCO's large electric customers with self-generation utilize the generation as a by-product of process steam production needs. The generation is not predictable, and, therefore, not dispatchable by the utility.

Data Source – Internal is collected internally by NIPSCO in its regular business activities pertaining to energy sales, demand, number of customers, and price for the forecasting process. NIPSCO collects internal peak hour MW, wholesale customers, large industrial customers and all other demand in addition to historical interruptions.

NIPSCO produces historical estimates of weather-normalized energy. Because industrial class energy consumption varies very little with weather, NIPSCO weather-normalizes kilowatt hour ("kWh") sales for the residential and commercial classes only. The normalization procedure uses coefficients obtained from regressions using ten years of monthly data of kWh/customer/day on CDD/day and HDD/day with additional terms for some month's CDD and a trend variable as appropriate.

The general normalization equation is specified on a monthly per day basis and then scaled to a monthly concept by multiplying by days:

Normal kWh/Customer = Actual kWh/Customer + ((CDD coefficient) * (Normal CDD – Actual CDD)) + (HDD coefficient * (Normal HDD – Actual HDD))
Where
Monthly Normal kWh = (Normal kWh/Customer * Customers) and
Annual Normal kWh is the sum of the monthly normal kWh.

The actual and normal energy sales for residential and commercial customers are shown in Figure 4-1 and Figure 4-2 below, respectively.

Figure 4-1
NIPSCO Residential GWh

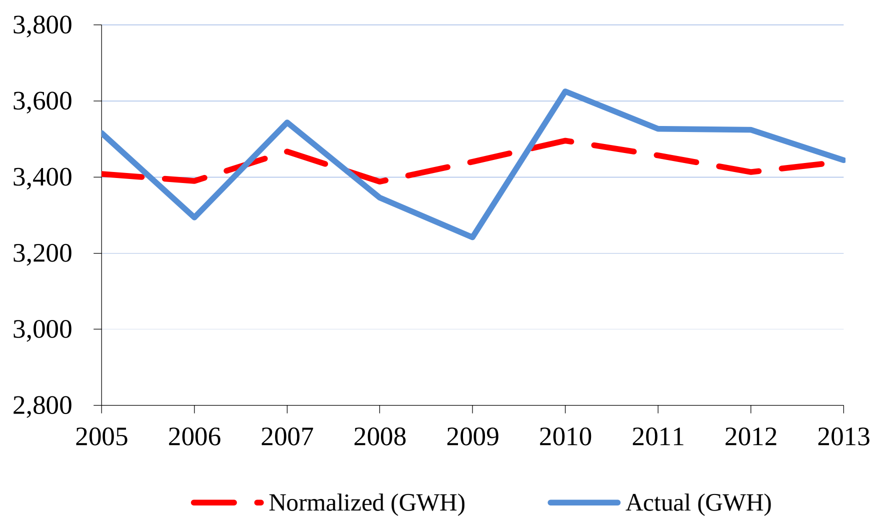
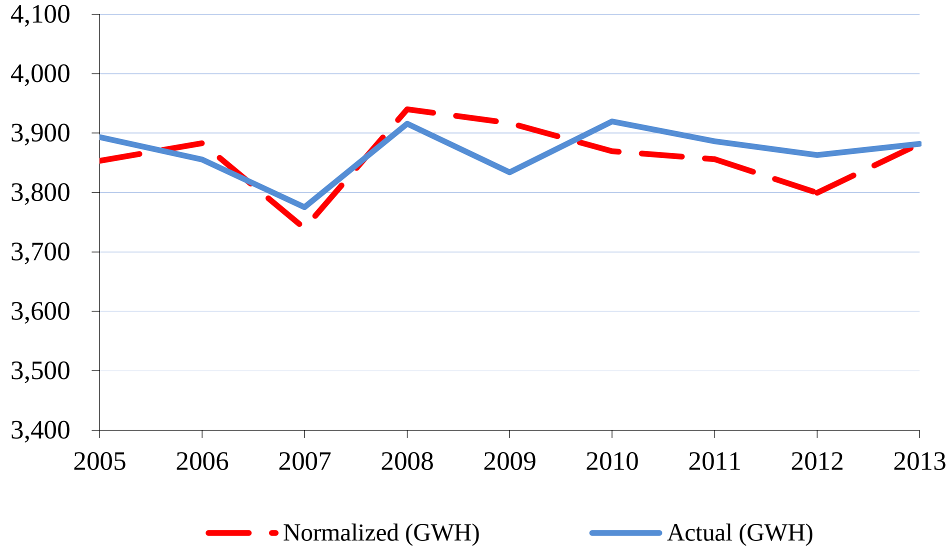


Figure 4-2
NIPSCO Commercial GWh



Data Sources - External:

Schneider Electric - NIPSCO used two weather measures in the forecast, specifically CDD and HDD as defined by the National Oceanic and Atmospheric Administration (“NOAA”). The Company purchases weather data for three NOAA stations: Valparaiso, South Bend and Fort Wayne. For modeling purposes, the weather from these three stations is represented as a weighted average with the weights based on the geographical distribution of the weather-sensitive load. For the forecast period, the Company assumed weather data to be equal to normal, defined as the 1976-2010 average for both CDD and HDD. The weighted weather concepts for the peak hour model are cooling degree hours, heating degree hours and relative humidity.

IHS Global Insight - NIPSCO purchased the economic and demographic data from IHS Global Insight. Economic data used in the production of the forecast represents the most current information from IHS Global Insight.

Itron, Inc. - Historical and forecasted saturation and efficiency data are obtained from Itron, Inc., a national utility consulting firm. Itron, Inc. produces an annual statistically-adjusted end use model by census region reflecting historical and future saturation and efficiency trends. Itron, Inc. works closely with the United States Energy Information Agency (“EIA”) to embed the EIA’s latest equipment saturation and efficiency trend forecasts into its annual models. NIPSCO used this information in the long-term residential forecast model.

Peak Hour Demand Forecast Model - The NIPSCO Peak Hour Demand Forecast Model is a function of composition and level of load –residential, commercial and industrial energy; cooling degree hours (summer) or heating degree hours (winter) at peak hour; and the level of relative humidity at peak hour.

Discussion of Forecast and Alternative Cases

High and Low Load Growth Cases

The high and low load growth cases were constructed from the base case forecast. High and low growth case gigawatt hours ("GWh") for the residential and commercial classes were calculated with the underlying model predicted values, along with the statistically estimated 95 percent confidence band around those values. The high growth case includes additional GWh sales reflecting industrial customer expansions currently being developed within NIPSCO's service territory. It also reflects additional industrial demand based on the load observed in 2013. Table 4-1 reflects NIPSCO's base, high and low load forecast scenarios for selected years before any savings from DSM programs are included ("BDSM").

Table 4-1 (BDSM)
NIPSCO IRP Scenarios - Selected Year

	Energy Sales - GWh			Internal Demand - MW		
	Base	High	Low	Base	High	Low
Year	GWh	GWh	GWh	MW	MW	MW
2014	18,448	19,329	17,257	3,208	3,338	3,038
2019	18,681	20,060	17,710	3,273	3,468	3,113
2024	19,066	20,762	18,129	3,372	3,607	3,202
2029	19,444	21,379	18,407	3,465	3,737	3,273
2034	19,784	21,928	18,594	3,558	3,864	3,337
		vs. Base			vs. Base	
		High	Low		High	Low
		GWh	GWh		MW	MW
2014	-	4.77%	-6.46%	-	4.1%	-5.3%
2019	-	7.38%	-5.20%	-	6.0%	-4.9%
2024	-	8.89%	-4.92%	-	7.0%	-5.0%
2029	-	9.95%	-5.33%	-	7.8%	-5.5%
2034	-	10.84%	-6.01%	-	8.6%	-6.2%

Forecast Results – Base Case

Over the forecast period, total energy and peak hour demand are projected to grow at 0.3 percent and 0.5 percent respectively. These rates are compounded annually before taking into account incremental DSM impacts. NIPSCO expects overall customer growth to increase about 0.5 percent annually. Table 4-2 illustrates NIPSCO's electric energy and demand forecast.

Table 4-2 (BDSM)
Electric Energy and Demand Forecast
FP0714c

Year	Energies (GWh) Total Retail *	% Change	Losses (GWh)	Total Output (GWh)	% Change	Load Factor	Internal Peak Hour (MW)	% Change
2004	16,191		720	16,911		66.1%	2,921	
2005	16,656	2.9%	740	17,396	2.9%	63.0%	3,154	8.0%
2006	16,767	0.7%	733	17,500	0.6%	61.7%	3,238	2.7%
2007	16,904	0.8%	751	17,655	0.9%	62.2%	3,239	0.0%
2008	16,705	-1.2%	897	17,602	-0.3%	65.3%	3,076	-5.0%
2009	14,925	-10.7%	858	15,783	-10.3%	66.8%	2,696	-12.4%
2010	16,191	8.5%	915	17,106	8.4%	62.9%	3,103	15.1%
2011	16,836	4.0%	892	17,728	3.6%	64.8%	3,122	0.6%
2012	16,756	-0.5%	925	17,681	-0.3%	62.0%	3,257	4.3%
2013	16,798	0.2%	839	17,638	-0.2%	63.0%	3,194	-1.9%
2014	17,488	4.1%	960	18,448	4.6%	65.7%	3,208	0.4%
2015	17,447	-0.2%	958	18,405	-0.2%	65.4%	3,212	0.2%
2016	17,492	0.3%	961	18,452	0.3%	65.4%	3,219	0.2%
2017	17,555	0.4%	964	18,519	0.4%	65.4%	3,235	0.5%
2018	17,627	0.4%	968	18,595	0.4%	65.3%	3,253	0.6%
2019	17,708	0.5%	972	18,681	0.5%	65.2%	3,273	0.6%
2020	17,777	0.4%	976	18,753	0.4%	65.0%	3,291	0.6%
2021	17,844	0.4%	980	18,823	0.4%	64.9%	3,311	0.6%
2022	17,920	0.4%	984	18,904	0.4%	64.8%	3,332	0.6%
2023	17,996	0.4%	988	18,984	0.4%	64.6%	3,352	0.6%
2024	18,073	0.4%	992	19,066	0.4%	64.5%	3,372	0.6%
2025	18,145	0.4%	996	19,141	0.4%	64.4%	3,391	0.6%
2026	18,217	0.4%	1000	19,218	0.4%	64.3%	3,410	0.6%
2027	18,290	0.4%	1004	19,295	0.4%	64.2%	3,429	0.6%
2028	18,364	0.4%	1008	19,372	0.4%	64.2%	3,447	0.5%
2029	18,432	0.4%	1012	19,444	0.4%	64.1%	3,465	0.5%
2030	18,502	0.4%	1016	19,519	0.4%	64.0%	3,483	0.5%
2031	18,562	0.3%	1019	19,582	0.3%	63.9%	3,497	0.4%
2032	18,627	0.3%	1023	19,650	0.3%	63.9%	3,511	0.4%
2033	18,690	0.3%	1026	19,716	0.3%	63.5%	3,542	0.9%
2034	18,754	0.3%	1030	19,784	0.3%	63.5%	3,558	0.4%
2035	18,819	0.3%	1033	19,853	0.3%	63.4%	3,574	0.4%
Compound Average Growth Rate 2014-2035								
	0.3%			**0.3%**			**0.5%**	

** Retail does not include bulk sales*

Table 4-3 displays the NIPSCO's forecast of Energies by Customer Class.

Table 4-3 (BDSM)
Energies by Customer Class
FP0714c

Year	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Other (GWh)	Total * (GWh)	Percent Change
2004	3,104	3,635	9,310	143	16,911	
2005	3,516	3,893	9,132	115	17,396	2.9%
2006	3,294	3,856	9,503	114	17,500	0.6%
2007	3,544	3,775	9,444	142	17,655	0.9%
2008	3,346	3,916	9,305	138	17,602	-0.3%
2009	3,241	3,834	7,691	159	15,783	-10.3%
2010	3,626	3,920	8,459	186	17,106	8.4%
2011	3,527	3,886	9,257	166	17,728	3.6%
2012	3,524	3,863	9,250	119	17,681	-0.3%
2013	3,445	3,882	9,340	132	17,638	-0.2%
2014	3,442	3,913	10,006	127	18,448	4.6%
2015	3,467	3,942	9,911	127	18,405	-0.2%
2016	3,498	3,978	9,889	127	18,452	0.3%
2017	3,525	4,012	9,890	128	18,519	0.4%
2018	3,556	4,052	9,891	128	18,595	0.4%
2019	3,587	4,096	9,896	128	18,681	0.5%
2020	3,614	4,138	9,896	129	18,753	0.4%
2021	3,636	4,182	9,896	129	18,823	0.4%
2022	3,663	4,231	9,896	130	18,904	0.4%
2023	3,692	4,278	9,896	130	18,984	0.4%
2024	3,725	4,322	9,896	130	19,066	0.4%
2025	3,751	4,367	9,896	131	19,141	0.4%
2026	3,781	4,410	9,896	131	19,218	0.4%
2027	3,810	4,453	9,896	131	19,295	0.4%
2028	3,843	4,493	9,896	132	19,372	0.4%
2029	3,869	4,534	9,896	132	19,444	0.4%
2030	3,899	4,575	9,896	132	19,519	0.4%
2031	3,928	4,606	9,896	133	19,582	0.3%
2032	3,961	4,637	9,896	133	19,650	0.3%
2033	3,986	4,675	9,896	133	19,716	0.3%
2034	4,015	4,709	9,896	134	19,784	0.3%
2035	4,045	4,744	9,896	134	19,853	0.3%
Compound Average Growth Rate 2014-2035						
	0.8%	**0.9%**	**-0.1%**	**0.3%**	**0.3%**	

**Includes Total Retail and Losses*

Table 4-4 displays the forecast of customer counts by class. For documentation of the forecast, see Appendix A.

Table 4-4
Customer Counts by Class
FP0714C

Year	Residential Customers	Commercial Customers	Industrial Customers	Other Customers	Total Customers
2004	392,342	50,332	2,528	770	445,972
2005	395,849	51,261	2,515	765	450,390
2006	398,349	52,106	2,509	759	453,723
2007	400,991	52,815	2,509	755	457,070
2008	400,640	53,438	2,484	754	457,316
2009	400,016	53,617	2,441	746	456,820
2010	400,522	53,877	2,432	740	457,571
2011	400,567	54,029	2,405	737	457,738
2012	401,177	53,969	2,445	758	458,349
2013	402,638	54,452	2,374	799	460,263
2014	403,762	54,701	2,215	725	461,402
2015	405,424	55,120	2,215	725	463,484
2016	407,236	55,516	2,215	725	465,692
2017	409,360	55,927	2,215	725	468,227
2018	411,541	56,469	2,215	725	470,950
2019	413,756	56,999	2,215	725	473,695
2020	416,019	57,507	2,215	725	476,466
2021	418,319	58,142	2,215	725	479,401
2022	420,645	58,771	2,215	725	482,356
2023	422,978	59,277	2,215	725	485,195
2024	425,283	59,792	2,215	725	488,015
2025	427,525	60,314	2,215	725	490,779
2026	429,728	60,849	2,215	725	493,518
2027	431,902	61,386	2,215	725	496,228
2028	434,037	61,787	2,215	725	498,764
2029	436,143	62,325	2,215	725	501,408
2030	438,227	62,733	2,215	725	503,900
2031	440,281	63,014	2,215	725	506,235
2032	442,305	63,429	2,215	725	508,675
2033	444,317	63,853	2,215	725	511,110
2034	446,307	64,146	2,215	725	513,393
2035	448,285	64,575	2,215	725	515,800
Compound Average Growth Rate 2014-2035					
	0.5%	**0.8%**	**0.0%**	**0.0%**	**0.5%**

Evaluation of Model Performance/Accuracy

NIPSCO tracks its forecast in terms of mean absolute error (“MAE”). Data for 2002-2013 show that the MAE of the one-year-ahead peak hour demand forecast is 3.8 percent before accounting for future DSM programs in the forecast; the two-year-ahead forecast has a 4.0 percent MAE; and the MAE for the five-year-ahead forecast is 4.4 percent These represent total forecast error including the effect of abnormal weather at peak. The comparable MAE for GWh sales is 3.0 percent for the one-year-ahead forecast; 3.5 percent for the two-year-ahead forecast; and 4.2 percent for the five-year-ahead forecast. On a before-DSM-basis, class comparisons to weather-normalized actual data show variances with residential and commercial of 1.5 percent and 2.9 percent MAE for the one-and two-year ahead forecasts. Industrial GWh are not weather normalized and show 5.7 percent and 6.4 percent MAE for the one-year-ahead and the two-year-ahead forecast before accounting for future DSM programs.

Tables 4-5 thru 4-8 show data for 2002-2013 for total GWh sales and peak hour MW and compare forecasts to actual data not normalized for weather. GWh sales by class are compared to actual data normalized for weather.

Table 4-5 (BDSM)
Internal Peak Hour Demand - MW
Absolute % Variance of Forecast vs. Actual

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	**Actual ***	**Forecast**	**% Var.**	**Forecast**	**% Var.**	**Forecast**	**% Var.**
2002	3,021	2,876	5.0%	2,953	2.3%	2,844	6.2%
2003	3,065	2,989	2.5%	2,931	4.6%	3,221	4.8%
2004	2,921	3,052	4.3%	3,030	3.6%	2,951	1.0%
2005	3,154	3,046	3.5%	3,091	2.0%	3,104	1.6%
2006	3,238	3,099	4.5%	3,077	5.2%	3,064	5.7%
2007	3,239	3,154	2.7%	3,134	3.4%	3,146	3.0%
2008	3,076	3,224	4.6%	3,188	3.5%	3,201	3.9%
2009	2,696	3,024	10.9%	3,248	17.0%	3,170	15.0%
2010	3,103	2,965	4.7%	3,088	0.5%	3,232	4.0%
2011	3,122	3,134	0.4%	3,093	0.9%	3,282	4.9%
2012	3,257	3,183	2.3%	3,195	1.9%	3,323	2.0%
2013	3,194	3,172	0.7%	3,306	3.4%	3,233	1.2%
Average			**3.8%**		**4.0%**		**4.4%**

** Actual peak not adjusted for weather. Forecasted peaks assume normal weather; therefore, variance includes weather effect.*

Table 4-6 (BDSM)
Total GWh including Losses
Absolute % Variance of Forecast v Actual

		1-Year Ahead		2-Year Ahead		5-Year Ahead	
Year	**Actual ***	**Forecast**	**% Var.**	**Forecast**	**% Var.**	**Forecast**	**% Var.**
2002	16,494	16,538	0.3%	16,733	1.4%	16,199	1.8%
2003	16,519	16,761	1.4%	16,907	2.3%	18,493	10.7%
2004	16,911	17,224	1.8%	17,078	1.0%	18,018	6.1%
2005	17,396	17,031	2.1%	17,531	0.8%	17,544	0.8%
2006	17,500	16,750	4.5%	17,235	1.5%	17,544	0.3%
2007	17,655	17,725	0.4%	16,916	4.4%	17,928	1.5%
2008	17,602	18,355	4.1%	17,938	1.9%	18,374	4.2%
2009	15,783	16,898	6.6%	18,446	14.4%	17,716	10.9%
2010	17,106	15,910	7.5%	17,340	1.3%	17,373	1.5%
2011	17,728	16,715	6.1%	16,931	4.7%	18,389	3.6%
2012	17,681	17,754	0.4%	17,220	2.7%	18,804	6.0%
2013	17,638	17,591	0.3%	18,622	5.3%	18,258	3.4%
Average			**3.0%**		**3.5%**		**4.2%**

** Actual GWh not adjusted for weather. Forecasted GWh assumes normal weather, therefore, variance includes weather effect.*

Table 4-7 (BDSM)
Residential and Commercial GWh
Absolute % Variance of Forecast v Actual

		1-Year Ahead		2-Year Ahead	
	Normal *	**Forecast**	**% Var.**	**Forecast**	**% Var.**
2010	7,366	7,431	0.9%	7,659	4.0%
2011	7,313	7,428	1.6%	7,474	2.2%
2012	7,213	7,382	2.3%	7,492	3.9%
2013	7,323	7,414	1.2%	7,427	1.4%
Average			**1.5%**		**2.9%**

** Adjusted for weather*

Table 4-8 (BDSM)
Industrial GWh
Absolute % Variance of Forecast v Actual

		1-Year Ahead		2-Year Ahead	
	Actual *	**Forecast**	**% Var.**	**Forecast**	**% Var.**
2010	8,459	7,692	9.1%	8,879	5.0%
2011	9,257	8,220	11.2%	8,629	6.8%
2012	9,250	9,243	0.1%	8,632	6.7%
2013	9,340	9,111	2.4%	10,020	7.3%
Average			**5.7%**		**6.4%**

** No weather effect measured for industrial load*

SECTION 5

Existing Resources

In This Section

NIPSCO serves customers with a portfolio of supply-side and demand-side resources. The resources are designed to match the characteristics of NIPSCO's load.

- *Supply-Side Resources used to serve customers include 3,405 MW of coal, natural gas and hydroelectric generation, as well as wind generation purchases.*
- *Demand-Side Resources include energy efficiency, energy conservation and demand response programs which help to reduce customers' electricity consumption, or shift energy consumption from peak consumption hours to off-peak hours.*
- *As a member of MISO, NIPSCO has access to an efficient, liquid market.*
- *NIPSCO actively manages fuel supplies to its coal and gas generators.*

Meeting Customers' Energy Needs

As part of the planning process, NIPSCO identifies existing resources. These resources must be capable of meeting customers' forecast capacity and energy needs. To be considered, the resources must be safe, reliable and cost effective. NIPSCO must also take into account the business climate in which we anticipate operating within.

NIPSCO also operates within MISO, the Regional Transmission Organization ("RTO"), and is subject to North American Electric Reliability Corporation ("NERC") standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization ("RRO"), ReliabilityFirst, standards approved by Federal Energy Regulatory Commission ("FERC").

Supply-Side Resources – A Description of NIPSCO's Generation Portfolio

NIPSCO's generation portfolio consists of the following sites:

- Bailly Generating Station ("Bailly")
- Michigan City Generating Station ("Michigan City")
- R.M. Schahfer Generating Station ("Schahfer")
- Sugar Creek Generating Station ("Sugar Creek")
- Norway and Oakdale Hydroelectric ("Norway Hydro" and "Oakdale Hydro")
- Two purchase power agreements ("PPAs") for wind generation ("Buffalo Ridge" and "Barton").

NIPSCO-Owned Supply Resource – Bailly

Bailly is located on a 100-acre site on the shore of Lake Michigan in Porter County, Indiana. Bailly's two base-load units and one peaking unit came on-line over a six-year period ending in 1968. The units are equipped with various environmental control technologies, including FGD to reduce sulfur dioxide ("SO_2"), Selective Catalytic Reduction ("SCR") and Over-Fire Air ("OFA") systems to reduce nitrogen oxide ("NO_x") emissions as required by law. Future EPA regulations for coal ash and cooling water may impact Bailly Units 7 and 8. The individual characteristics of the Bailly units are provided on Table 5-1.

Table 5-1
Bailly Unit Information

	Unit 7	Unit 8	Unit 10
NET Output			
Min (MW)	100	200	----
Max (MW)	160	320	31
Boiler	Babcock & Wilcox	Babcock & Wilcox	----
Burners	4 Cyclone	8 Cyclone	----
Main Fuel	Coal	Coal	Gas
Turbine	General Electric	General Electric	Westinghouse
Frame	D6	G2	W301G
In-Service	11/30/62	7/31/68	11/30/68
Environmental Controls	FGD, SCR, OFA	FGD, SCR, OFA	----

NIPSCO-Owned Supply Resource - Michigan City

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. Michigan City has one base-load unit, Unit 12. It is equipped with SCR and OFA systems to reduce NO_x emissions as required by law. Unit 12 burns low and medium sulfur coal blends to minimize SO_2 emissions. Major upgrades for emissions controls are being evaluated for installation on Unit 12 in order to comply with the Consent Decree,[1] the Maximum Achievable Control Technology ("MACT") and Cross-State Air Pollution Rule ("CSAPR"). An FGD system is currently under construction for Unit 12; the system will be in service in 2015. EPA regulations for coal ash and cooling water may also impact Michigan City Unit 12. The individual unit characteristics of Michigan City are provided on Table 5-2.

[1]January 13, 2011 agreement among the EPA, Department of Justice, Indiana Department of Environmental Management and NIPSCO to settle the NIPSCO EPA New Source Review Notice of Violation lodged with the United States District Court for the Northern District of Indiana Hammond Division ("Northern District") (the "Consent Decree"). The Consent Decree was placed on public notice in the Federal Register on January 20, 2011. On July 22, 2011, the Northern District issued an Order in Case No. 2:11-CV-16 JVB approving the Consent Decree. The Consent Decree requires that NIPSCO operate all existing pollution control equipment and install additional pollution control equipment.

Table 5-2
Michigan City Unit Information

	Unit 12
NET Output	
Min (MW)	250
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	Coal
Turbine	General Electric
Frame	G2
In-Service	5/31/74
Environmental Controls	SCR, OFA

NIPSCO-Owned Supply Resource - Schahfer

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. Schahfer is the largest of NIPSCO's generating stations. Schahfer's four coal-fired base-load units and two gas-fired simple cycle peaking units came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce SO_2 emissions and SCR, Low NO_x Burners ("LNB") and OFA systems to reduce NO_x emissions as required by law. Unit 14 burns low and medium sulfur coal blends and Unit 15 burns low-sulfur coals to minimize SO_2 emissions. As part of the Company's Clean Air Interstate Rule ("CAIR") Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. Installation of a new LNB with OFA system was completed on Unit 15 in 2009. A new FGD plant on Unit 14 was placed in service in 2013. FGD installation on Unit 15 is in progress and expected to be completed in 2014. EPA regulations for coal ash and cooling water may also impact Schahfer. The individual unit characteristics of Schahfer are provided in Table 5-3.

Table 5-3
Schahfer Unit Information

	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	250	200	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	12/31/76	10/31/79	4/28/83	2/14/86	12/31/79	12/31/79
Environmental Controls	FGD, SCR, OFA	LNB, OFA	FGD, LNB, OFA	FGD, LNB, OFA	----	----

NIPSCO-Owned Supply Resource - Sugar Creek

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired combustion turbines ("CTs") and combined cycle gas turbine ("CCGT") were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is NIPSCO's newest electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two CT generators and one steam turbine generator are operated in the CCGT mode. Environmental control technologies at Sugar Creek include SCR to reduce NO_x, and dry low NO_x ("DLN") combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 5-4.

Table 5-4
Sugar Creek Unit Information

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	110	110	110
Max (MW)	152	154	229
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA	7FA	D11
In-Service	6/15/2002	6/15/2002	6/15/2003
Environmental Controls	SCR, DLN	SCR, DLN	---

NIPSCO-Owned Supply Resource - Norway Hydroelectric and Oakdale Hydroelectric

Norway Hydroelectric is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydroelectric has four generating units capable of producing up to 7,200 kilowatts (“kW”). However, Norway Hydroelectric output is dependent on river flow and the typical maximum plant output is four MW. The individual unit characteristics of the Norway Hydroelectric are provided in Table 5-5.

Table 5-5
Norway Hydroelectric Unit Information

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydroelectric is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydroelectric has three generating units capable of producing up to 9,200 kW. However, the Oakdale Hydroelectric output is dependent on river flow and the typical maximum plant output is six MW. The individual unit characteristics of the Oakdale Hydroelectric are provided in Table 5-6.

Table 5-6
Oakdale Hydroelectric Unit Information

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

NIPSCO PPAs - Barton and Buffalo Ridge Wind

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 5-7.

Table 5-7
Barton Wind Information

NET Output	
Per Unit (MW)	2.0
Number of Units	25
Total Output (MW)	50.0
In-Service	04/10/2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County, South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 5-8.

Table 5-8
Buffalo Ridge Wind Information

NET Output	
Per Unit (MW)	2.1
Number of Units	24
Total Output (MW)	50.4
In-Service	04/15/2009
Main Fuel	Wind

Total Resource Summary/Portfolio Composition

Table 5-9 provides the net capacity, type of fuel burned and in-service dates for each of NIPSCO's existing generating units.

Table 5-9
Existing Generating Units

Unit	NDC (MW)	Type	Typical Fuel	In-Service Date
Michigan City 12	469	Steam	Coal	May 31, 1974
Bailly 7	160	Steam	Coal	November 30, 1962
Bailly 8	320	Steam	Coal	July 31, 1968
Bailly 10	31	Combustion Turbine	Natural Gas	November 30, 1968
Schahfer 14	431	Steam	Coal	December 31, 1976
Schahfer 15	472	Steam	Coal	October 31, 1979
Schahfer 16A	78	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 16B	77	Combustion Turbine	Natural Gas	December 31, 1979
Schahfer 17	361	Steam	Coal	April 28, 1983
Schahfer 18	361	Steam	Coal	February 14, 1986
Norway	4	Hydro	Hydro	June 8, 1923
Oakdale	6	Hydro	Hydro	November 11, 1925
Sugar Creek CT 1A	152	Combustion Turbine	Natural Gas	June 15, 2002
Sugar Creek CT 1B	154	Combustion Turbine	Natural Gas	June 15, 2002
Sugar Creek SCST	229	Steam	Natural Gas	June 15, 2003
Barton(PPA)	50	Wind	Wind	April 10, 2009
Buffalo Ridge(PPA)	50	Wind	Wind	April 15, 2009
Subtotal	2,574		Coal	
Subtotal	721		Natural Gas	
Subtotal	10		Hydro	
Subtotal	100		Wind	
Total System	**3,405**			

NIPSCO and the MISO Wholesale Electricity Market

NIPSCO's View of MISO's Generation Resource Pool

MISO demonstrates an important trait key to NIPSCO's long term plans – ongoing liquidity. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. There are many changes that affect MISO's generation resource pool. In addition to changes in MISO membership, there are many regulatory concerns that are being monitored.

MISO Membership

Entrants – In 2013, the integration of the new MISO South Region added over 18,000 miles of transmission, approximately 50,000 MW of generation capacity, and approximately 30,000 MW of load into the MISO footprint. MISO's increased scale will drive benefits through improved reliability and reduced regulation and spinning reserve requirements by consolidating balancing authorities and expanded options for generation commitment and dispatch from a more diverse set of fuel types.

Exits - Since First Energy, Duke Ohio and Duke Kentucky left the MISO and joined the PJM Interconnection LLC in 2011, there have been no other exits from the MISO footprint.

Potential Regulatory Impacts - MISO has completed several studies on the impact of proposed EPA rules on its resource pool as well as conducted a joint survey with the Organization of MISO States ("OMS"). Approximately 40 percent of MISO's generation is sourced from coal units. It was estimated that about half of MISO's coal generation pool would require additional controls to comply with EPA rules. Due to the high cost of retrofits, some coal units have announced their intention to retire. MISO reported at the February 2014 Supply Adequacy Working Group meeting that the MISO North and Central Regions were facing a potential combined two GW shortage by 2016, while the MISO South Region is projecting a five GW surplus. Transfer limits between the North/Central and South Regions are being addressed in several MISO Stakeholder forums. With the understanding that supply projections constantly change, NIPSCO is participating in MISO's continued efforts to conduct impact studies to address these issues.

The discussion continues surrounding a national and/or Indiana-specific requirement related to the use of renewable resources. While NIPSCO has been proactive in securing renewable (wind) resources, any additional standards related to renewable energy would have an impact on future resource considerations. MISO currently has approximately 12,500 MW of wind generation within its footprint, and approximately 15,000 MW of wind generation in the active study queue. Operational issues concerning the amount of wind generation in the MISO queue and wind generation saturation are being addressed in various MISO Stakeholder committees.

MISO is also accommodating demand-side resources into its markets. Demand-side resources come in many different forms including load modifying resources, emergency demand response, and behind the meter generation. Rules are being developed to afford these resources the same opportunity as traditional generation to the extent possible. NIPSCO supports the development of demand response as a resource and is an active participant in the Stakeholder process.

Fuel Management for Supply-Side Resources

Coal Procurement and Inventory Practices

Coal Acquisition Strategy - NIPSCO employs a multifaceted strategy to guide coal supply and acquisition activities associated with the fueling of its coal-fired units. This strategy includes: 1) procuring the best coal for efficient unit operations; 2) providing for environmental compliance; 3) maintaining targeted inventory levels; 4) ensuring delivery of coal in a timely and cost-effective manner; and 5) maximizing contractual flexibility by procuring coal types that can be used in more than one unit.

Coal Procurement - NIPSCO maintains a five-year baseline coal strategy. This strategy is used as a tool to determine appropriate coal purchases and inventory requirements. The fuel budget is dynamic and is updated on a periodic basis in response to system needs and market conditions.

Coal Pricing Outlook – Coal is generally sold in a bilateral market on a contract basis. Coal competes for market share against other fuels on a "value in use" basis, i.e., environmental externalities price in to the value of the commodity. Also, coal prices are linked with the supply and demand for coal, coal extraction costs, transport costs, and more generally with the overall supply and demand balance for energy. The discovery and exploitation of North American shale gas resources appears to have fundamentally altered the price relationship between coal and natural gas. Natural gas prices have declined and remain low while coal prices have continued to rise with higher mining costs, rail transport costs, and increased government regulations related to the mining of coal.

Generally rising coal prices and declining Appalachia coal production have brought market share to the Illinois Basin, which is higher in sulfur than coal from other regions. Several new mines have opened up in the Illinois Basin, particularly in Illinois. With its higher sulfur content, Illinois Basin coal is viewed as being a potential export resource, but also available for domestic use with the installation of scrubbers. Southeast utilities are targeting Illinois Basin coal on a long-term basis as a replacement for Columbian and Central Appalachia coal.

PRB tends to be lower Btu producing than coal from other regions. Domestic utilities that have traditionally not burned PRB coal are evaluating blending lower Btu PRB coal with Central Appalachian and Illinois Basin coals to reduce their overall fuel costs. Additionally, Asian demand for PRB coal continues to grow, as Japan is building new high efficiency coal units, and new coal plants are being built in Korea and Taiwan as they prepare to meet their future electricity demand. Similarly, Central Appalachian and Northern Appalachian coal continues to be exported due to the demand for metallurgical coal.

Coal prices may also be impacted by regulations developed to protect miners, particularly in underground mines. These regulations may impact productivity and the increased compliance costs could be passed on to coal customers. However, this is not expected to be a major contributor to future coal prices.

Lastly, although coal still enjoys an economic advantage over natural gas, current and future environmental regulations may jeopardize. With government regulation in the mining industry, environmental regulations impacting air and water, and the potential of the government declaring fly ash a hazardous waste, this economic advantage continues to erode. As such, NIPSCO will continue to monitor coal prices in subsequent planning activities.

NIPSCO Coal Pricing Outlook - NIPSCO currently procures coal from three geographic regions in the United States, the PRB, Illinois Basin, and Northern Appalachia. Market demand for Illinois Basin coal has increased for reasons stated above, and therefore, prices have steadily risen. Northern Appalachia coal used by NIPSCO as a blend fuel in two of its cyclone units is being exported as a near metallurgical coal. This coal has a robust market overseas and is consequently priced accordingly. Also, the price of Northern Appalachia coal is expected to remain volatile due to its higher heat content and its international appeal compared to Illinois Basin and PRB coal. Pricing for PRB coal remained relatively stable in 2013. The PRB pricing is expected to gradually escalate in 2014 due to strong demand as a result of recent inventory depletion caused by exceptional winter weather conditions in late 2013 and early 2014.

Coal and Issues of Environmental Compliance - Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to be to meet these environmental requirements.

Maintenance of Coal Inventory Levels - NIPSCO has an ongoing strategy to maintain a stable, controllable coal inventory. NIPSCO reviews inventory target levels annually and makes adjustments in anticipation of changes in supply availability relative to demand, transportation constraints and unit consumption. NIPSCO modifies target inventory levels on a unit-by-unit basis depending on the unit consumption, transportation cycle times, reliability of coal supply and station coal handling operations.

Forecast of Coal Delivery and Transportation Pricing - To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts contemporaneously with coal supply contracts and evaluates all fuel procurement options on a delivered basis, which includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have become more fluid in all geographic regions, particularly shipments originating in the PRB region due to infrastructure improvements. Railroads will need to continue making major investments in infrastructure and capital equipment to ensure timely deliveries and ease railroad congestion.

Transportation rates continue trending upward and one of the driving factors is the volatility of diesel fuel. Railroads incorporate fuel surcharge mechanisms in transportation agreements to allow for recovery of the cost of the diesel fuel. NIPSCO verifies that all fuel surcharges imposed by the railroads meet the contractual terms of the transportation agreement negotiated by the parties.

NIPSCO Transportation Pricing Outlook - NIPSCO has limited rail options at the origin and destination for most of its transportation moves, and is further disadvantaged due to its geographical location. Not only is rail transportation limited, other transport modes (trucking and barging) are not feasible at this time. Further, NIPSCO's largest generating station, Schahfer, is served by only one railroad. All coal delivered by this railroad to Schahfer is transported under escalated transportation rates and onerous fuel surcharges. Increased rail competition, particularly at Schahfer, would mitigate these costs. A north/south Indiana railroad providing direct access to Schahfer, and potential access to other industry in northern Indiana, and the Port of Indiana, would allow Schahfer direct access to burn Indiana coal, and also be a possible economic stimulus for the northern region. Currently, the interchange for Indiana coal transported to Schahfer is near Chicago, adding miles to the transport route, increasing the delivered cost of Indiana coal to the station.

PRB and Illinois Basin transportation rates currently, and in the near term, have remained relatively stable. Fuel surcharges continue to fluctuate with the changing West Texas Intermediate Crude pricing.

Coal Contractual Flexibility, Deliverability and Procurement - Coal purchasing contracts are typically three to five years in term. Spot purchases are made on an as-needed basis in response to inventory fluctuations. In an effort to avoid inventory fluctuations and accommodate unit maintenance outages, most coal types under contract can be used in more than one unit. The fuel blending strategy can also be adjusted to conserve a particular type of coal if supply problems are being experienced. Both coal and rail transportation contracts have force majeure clauses, which cover events beyond the reasonable control of the party affected that prevent the mining, processing, or loading of coal at the mines, receiving, transporting, or delivering of coal by the rail carriers, or accepting, unloading, or burning of coal at the generating stations.

Natural Gas Procurement and Management

Sugar Creek Generation Station - NIPSCO currently procures natural gas for its Sugar Creek Generating Station using a natural gas supply contract with an energy manager who delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on the interstate pipeline, Midwestern Gas

Transmission Company. NIPSCO releases the capacity to the energy manager. The contract has provisions to purchase next day and intraday firm gas supplies to serve the daily needs of the facility. The current energy management contract is set to expire on March 31, 2015. NIPSCO nominates and balances the gas supply needs of the Sugar Creek Generating Station. A portion of the gas supply for Sugar Creek is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

Bailly, Michigan City and Schahfer Coal Units and Combustion Turbines - The coal units at NIPSCO's Bailly, Michigan City and Schahfer stations, and combustion turbines at Bailly and Schahfer are located within the NIPSCO natural gas local distribution company service territory. NIPSCO maintains a separate contract for firm delivered natural gas supply and energy management for these units. The contract has provisions to nominate next-day usage based on the expected usage of each generating station. The actual usage is balanced daily and balancing is the responsibility of the energy manager.

Electric Generation Gas Supply RFP Process - NIPSCO conducts two separate RFPs for the electric generation firm natural gas supply, one for the Sugar Creek facility and a separate one for the coal units and combustion turbines. The RFP process may be done on a seasonal or annual basis depending on the current contract length and supplier agreement. The process includes qualifying potential suppliers, customizing the RFP based on near-term system needs and gas supply trends. Suppliers are chosen based on the overall value of the package and ability to serve the needs of the facility. To date, NIPSCO has entered into electric generation gas supply agreements that extend no longer than one year but is always evaluating the value and benefits of longer term agreements.

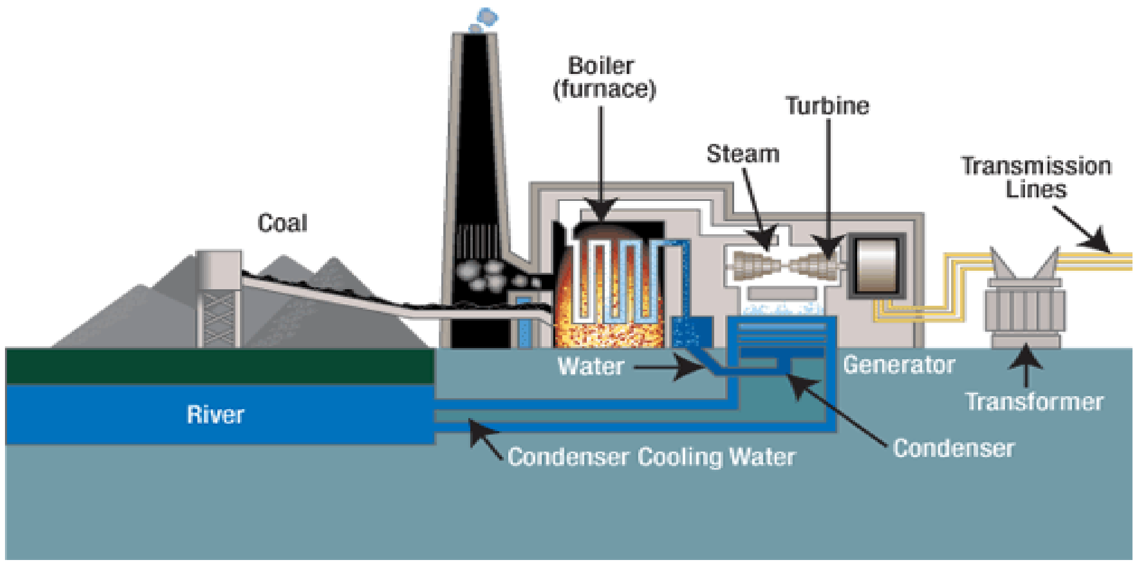
NIPSCO Water Usage Profile

NIPSCO is committed to serving as responsible stewards of natural and environmental resources. As part of that commitment, NIPSCO strives to conserve the fresh water resources of the Great Lakes and Mississippi River Basins. Both coal-fired and CCGT units use water as the working medium. NIPSCO's units withdraw water both to generate steam and to provide cooling water for condensers. A brief description of water usage in the processes follows.

- Coal-Fired Units - 1) Purified water is pumped through pipes into the boilers. There, temperatures of up to 1,000 degrees Fahrenheit turn the water into steam. 2) The pressurized steam is then directed to the turbines. The steam spins the turbines, which turn an electric generator, thereby generating electricity. 3) The steam is then directed into a condenser, where it is cooled by the cooling water system. The condenser dissipates the heat and converts the steam back into liquid water. 4) For units with cooling towers such as Schahfer and Michigan City, water is evaporated from the process to cool the circulating water prior to it being returned to the condenser. The evaporated water is emitted from the unit as steam, and the remainder of the water is either recirculated or discharged into the source body of water. For units without cooling towers such as Bailly, nearly all of the cooling water withdrawn is returned to its source. See Figure 5-1.

Figure 5-1

Once-Through Cooling System - Coal-Fired Unit



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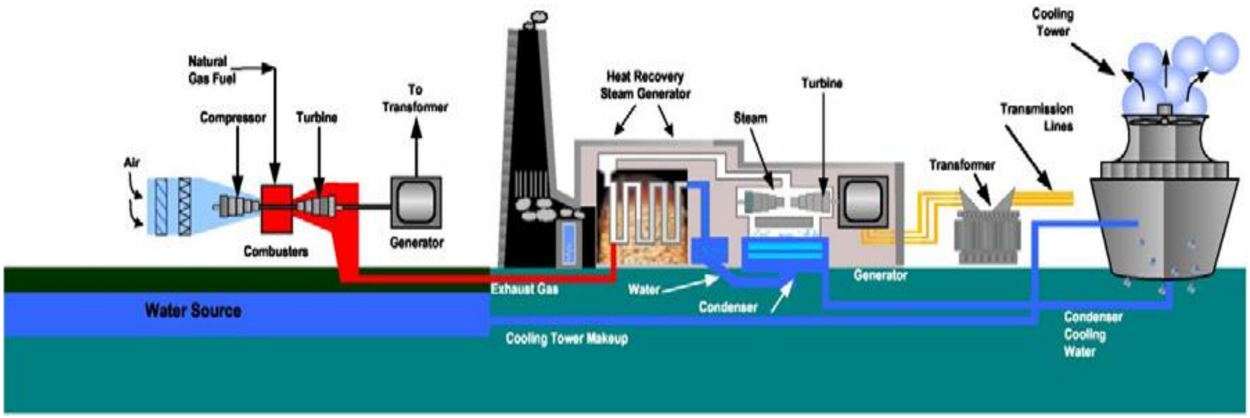
- CCGT Units - A CCGT facility such as Sugar Creek generates electricity in two cycles. 1) Electricity initially is generated using a gas turbine. 2) The waste heat from the gas combustion process is then used to make steam, thereby generating additional electricity via a steam turbine. This last step enhances the overall efficiency of the electric generation. The steam leaving the turbine is then directed into a condenser, where it is cooled by the cooling water system. The condenser dissipates the heat and converts the steam back into liquid water. The cooling water is pumped through mechanical draft cooling towers, and returned to the source waterway. Some steam is lost through the cooling towers. See Figure 5-2.

Figure 5-2
Cooling System - CCGT Unit



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Natural and Regulatory Environment

The Bailly and Michigan City Generating Stations sit on the shore of Lake Michigan in the Great Lakes Basin. The electric generation plants draw their water from Lake Michigan and one of its tributaries. Like all water withdrawals from Lake Michigan, Bailly's and Michigan City's usage is heavily regulated by international, federal, and state law. The primary guiding document is the Great Lakes Compact ("Compact"), an agreement that has been ratified by the United States, two Canadian provinces, and eight Great Lakes States. Indiana statutes passed pursuant to the Compact require large existing users to document their usage and to implement water conservation programs. New uses inside the Great Lakes Basin are closely scrutinized and new uses outside the basin are generally prohibited. NIPSCO is fully supportive of the Great Lakes Compact, and, in fact, worked with the State of Indiana to develop ways to implement the Compact. NIPSCO operates its generating stations in compliance with the Compact and Indiana water-use laws.

The Schahfer and Sugar Creek Generating Stations are located on the Kankakee and Wabash Rivers, both of which eventually flow into the Mississippi River. The State of Indiana comprehensively regulates the consumptive use of water in the Kankakee River Basin. NIPSCO has obtained a permit from the Indiana Department of Natural Resources for water withdrawals from the Kankakee River.

NIPSCO Water Usage

As noted above, steam turbine generating units use water in their processes. The majority of this water, however, is either recirculated or returned to the source body of water. The following table shows the estimated water usage during 2013. See Table 5-10.

Table 5-10
2013 Water Usage Generating Station

	Million Gallons / Day		
	Withdrawal	**Return**	***Consumption***
Michigan City	12.8	8.0	4.8
Bailly	211.4	210.7	0.7
Schahfer	24.5	12.2	12.3
Sugar Creek	2.3	0.9	1.4
Total	**251.0**	**231.9**	**19.1**

As is clear from the data above, coal-fired units without cooling towers like Bailly withdraw the most water in their processes. These units, however, also return proportionately more water to the source. In 2013, Bailly returned 99 percent of the water it withdrew.

Water Usage for Self-Build Options
See Engineering Study (CONFIDENTIAL Appendix K).

Operations Management and Dispatch Implications for Supply-Side Resources

Considerations for Environmental Compliance
As previously noted, NIPSCO entered into a Consent Decree with the EPA requiring NIPSCO to reduce emissions over a defined period of years through primarily capital improvements on existing generation resources. In addition, an EPA mandated MACT rule required NIPSCO to design and obtain approval to meet new air emission standards. In order to meet the terms of the Consent Decree and the MACT requirements, NIPSCO utilizes predictive tools to predict effluent emission levels based on unit operations, as well as determine levels of output for the individual generators that can help reduce the overall emissions. Based on output from the predictive tools and current operations statistics, NIPSCO also has the ability to modify unit operations and unit offers for dispatch into MISO as needed in order to remain environmentally compliant.

NIPSCO Demand-Side Management Strategy

NIPSCO has adopted a cultural change that encourages energy conservation and efficiency. NIPSCO actively promotes the benefits of energy efficiency to its employees and customers. Employees, especially those with direct customer contact, are encouraged to promote conservation.

2014 Core Programs

Residential Lighting Program
This program is designed to identify and implement the best approach to achieve the participation and energy saving goal for ENERGY STAR (“ES”) ES-qualified lighting products by each participating utility by program year. The Residential Lighting Program goal is to increase the penetration of ES qualified lighting products utilized in residences located in the service territory of each participating utility.

Residential Home Energy Assessment Program

This program is designed to generate energy savings for qualifying residential customers by providing low-cost energy efficiency measures and improvement recommendations tailored to customer homes. Key objectives include 1) help customers identify opportunities to better manage their energy use, and 2) maximize cost-effective savings via direct installation of low-cost energy savings. The goals of the Residential Home Energy Audit Program are to produce long term, cost effective electric savings in the residential market sector by helping customers analyze and understand their energy use, recommending appropriate weatherization measures, and facilitating the direct installation of specific low-cost energy saving measures.

Residential Income Qualified Weatherization Program

This program is designed to generate energy savings for qualifying low-income residential customers by providing energy efficiency measures and improvements tailored to participating customer homes as well as providing education to reduce energy consumption. Key objectives include 1) help customers identify opportunities to better manage their energy use, 2) maximize energy savings via direct installation of energy savings measures, 3) leverage and develop local resources such as auditors and installers, 4) leverage opportunities for collaboration and coordination of weatherization measures, provided by gas utility low income weatherization programs as well as benefits provided from other local, state and federal funding sources, and 5) identify significant health and safety concerns of the homes that impact eligibility. Goals of the Income Qualified Weatherization include producing long term energy and demand savings in the residential market sector through 1) the installation of energy-saving measures, 2) education of consumers during the audit process on ways to reduce energy consumption 3) the identification of opportunities for weatherization measures, 4) the professional installation of weatherization and efficiency measures, and 5) diagnostics of pre- and post-installation.

Energy Efficient Schools (School Education Kits and School Audit) Program

This program is designed to generate cost-effective electric savings through an elementary education and take-home kit program as well as a school energy audit program for K-12 schools. Key objectives include 1) help customers identify opportunities to better manage their energy consumption, 2) maximize cost-effective savings via provision of take-home kits of low-cost energy, savings measures to students, 3) promote the installation of energy efficient measures and operating procedures in K-12 school buildings, and 4) leverage opportunities for collaboration and coordination of school programs provided by gas utilities. The Energy Efficient Schools Program goal is to produce cost effective electric savings by influencing students and their families to focus on conservation and the efficient use of electricity. Another component of the program goal is to produce electric savings by providing technical assistance to schools in the form of building energy audits as well as provide access to prescriptive rebates programs. The program consists of two components 1) a school education program for both public and private K-12 students attending schools served by NIPSCO, and 2) a school technical assistance program that provides building energy audits to identify operation and capital improvements to school facilities served by the participating utilities.

Commercial & Industrial Prescriptive Rebates Program

This program is designed to assist commercial and industrial customers in reducing electrical energy consumption and costs. The program provides a prescriptive incentive structure that rewards with monetary incentives based on the installation of energy efficient equipment upgrades such as energy efficient light fixtures and ballasts as well as energy efficient pumps, motors and variable speed drives.

2014 Core Plus Programs

Residential Weatherization Program

This program is designed to produce long-term cost-effective electric and gas savings in the existing residential buildings market. This program has been designed to provide services, such as insulation, and duct sealing, to NIPSCO electric only customers, NIPSCO combination gas and electric customers and NIPSCO gas customers receiving electric service from Indiana Michigan Power ("I&M"). Customers typically purchase and install energy efficiency improvements and services when they are educated on opportunities, costs and benefits. This program is currently implemented by CLEAResult.

Residential Energy Conservation Program

This program is designed to significantly increase customer engagement across the selected population within NIPSCOs service territory, for the purposes of 1) large-scale, measurable and cost-effective energy savings, over a one year period, 2) increased program participation in select NIPSCO Energy Efficiency and DSM programs, and 3) increased customer satisfaction through an improved customer experience and engagement. This program is currently implemented by Opower.

Residential Multi-Family Direct Install Program

This program is designed to reduce energy consumption for tenants of multifamily units. The program is designed to affect the installation of energy efficient, high-performance water fixtures (i.e., showerheads and faucet aerators) and Compact Fluorescent Lamps ("CFLs") in rental units, condominiums, and mobile homes to substantially reduce the consumption of hot water and electrical consumption. This program is currently implemented by CLEAResult.

Residential New Construction Program

This Program provides incentives to offset a portion of the incremental costs incurred to meet the revised ES home certification program and exceed the performance of the upcoming adoption of the 2009 International Energy Conservation Code ("2009 IECC") in Indiana. The Program provides builders with education about energy efficient construction and the ways to meet and exceed them. Incentives are available to builders for both gas and electrically heated homes. This program is currently implemented by CLEAResult.

A/C Cycling Program

This voluntary program is available to NIPSCO electric customers with air conditioning units of five tons or less. A load control switch will be installed near the customer's central air conditioning unit. The radio-controlled switch will allow NIPSCO to cycle the customer's air conditioning compressor on and off for short periods of time during peak usage demands. Cycling occurs only during the weekdays during the summer. Customers participating in the program receive a $10/month credit on their bills from June – September. This program is currently implemented by GoodCents.

Residential Appliance Recycling Program

This program is designed to focus on older, less efficient electric appliances and offers cash incentives to recycle old, inefficient refrigerators and freezers. Customers receive a cash incentive for each functioning refrigerator and freezer, and the vendor hauls them away at no cost to be dismantled and recycled in an environmentally responsible way. This program is currently implemented by Appliance Recycling Center of America ("ARCA").

Residential Energy Efficiency Rebate Program

The Energy Efficiency Rebate Program provides cash rebates to NIPSCO residential customers who purchase select energy efficient equipment including furnaces, boilers, etc. The Program promotes the purchase of high efficiency home appliances such as heat pumps, and electronically commutated motors with a design that is flexible to adjust to constantly changing marketplace demands. This program is currently implemented by CLEAResult.

Commercial and Industrial Custom Program

Unique efficiency opportunities for the commercial and industrial customer are developed through a custom approach for site specific measures and prescriptive custom measure that are a standard established maintenance effort, or a measure unique to the commercial and industrial sector that is consistent in application and savings are transferable to non-site specific locations by previous tests or a site test valid for other locations. The incentive is paid as $/kWh saved, for site specific system or equipment efficiency improvement. This program is currently implemented by Franklin Energy.

Commercial and Industrial New Construction Program

Construction firms routinely instruct their design teams to produce energy efficient, high performing buildings, and architectural and engineering firms have the technical expertise and adequate compensation to respond to market demand. There is a market-driven opportunity to achieve energy efficiency and transform design and equipment specification practices at minimal cost when new buildings are designed and constructed, and when existing ones are renovated or expanded. The fundamental energy impact of early building design decisions may continue for its full life. Equipment choices establish energy consumption patterns for twenty to thirty years, until that initial equipment fails. This program provides, or co-funds, technical services and incentives to influence the energy efficiency of individual buildings and, over time, to change standard building design and equipment specification practices. This program is currently implemented by Franklin Energy.

Commercial and Industrial Guest Room Energy Management Program

The Guest Room Energy Management ("GREM") Program aims to achieve energy savings in hospitality facilities by offering customers direct installation of GREM controls for a nominal co-payment. GREM saves energy by reducing heating and cooling energy when the room is unoccupied. Eligible measures include: GREM controllers, vending machine misers, CFLs, bathroom occupancy sensors, low flow showerheads, and aerators. Services include an assessment of the facility and direct installation of the measure. This program is currently implemented by Franklin Energy.

Commercial and Industrial Small Business Direct Install Program

The Commercial and Industrial Small Business Direct Install ("SBDI") Program is a direct installation approach to penetrate the small commercial customer market, based on evidence that small customers do not have the expertise, time or available capital to make efficiency upgrades. This approach provides direct install measures for the customer and virtually eliminates the barriers of participant hassle and search costs. Direct installation programs can be ramped up quickly to achieve immediate, cost-effective savings. These programs also ensure that smaller customers receive program benefits consistent with their contribution to the energy efficiency program. This program is administered by Franklin Energy.

The 2014 projected energy savings are summarized by program in Table 5-11.

Table 5-11
2014 Projected Energy Savings (MWh)

Programs	Savings
2014 Core Programs	
Residential Lighting Program	16,633
Residential Home Energy Assessment (HEA) Program	8,081
Residential Income Qualified Weatherization (IQW) Program	2,571
Energy Efficient Schools Program	
School Education Kits	1,747
School Audit	1,122
Commercial and Industrial Prescriptive Rebate Program	56,481
Total Core Program	**86,635**
2014 Core Plus Programs	
Appliance Recycling Program	3,972
Residential Energy Efficiency Rebate Program	4,337
Weatherization Program	782
Direct Install Program (Multi-family)	5,901
Conservation Program	23,982
Residential New Construction Program	442
A/C Cycling Program	-
Non-Residential New Construction Program	6,610
C&I Custom Incentive Program	92,791
Small Business Direct Install Program	7,580
Guest Room Energy Management Direct Install Program	6,306
Total Core Plus Program	**152,703**
Total 2014 Electric DSM Program	**239,338**

2015 DSM Programs

On March 27, 2014 Senate Enrolled Act 340 became law which, among other things, removed the requirement that utilities meet the goals established by the Commission in the Phase II Order and eliminated the Core programs offered by a single TPA. As a result, NIPSCO chose to continue offering its customers DSM Programs in 2015 and in early June filed its proposed 2015 DSM Plan with the IURC. The following is a brief description of NIPSCO proposed 2015 Residential and C&I programs.

Residential Lighting Program

The Residential Lighting Program will provide incentives and marketing support through retailers to build market share and usage of ES and other energy efficient lighting products. The program will target the purchase of lighting products through in-store promotions as well as special sales events. Customer incentives facilitate the increased purchase of high-efficiency products while in-store signage, sales associate training and support makes provider participation easier.

Residential Elementary Education Program

The Residential Elementary Education Program provides energy education to students, providing an excellent opportunity to influence energy behavior over the long-term. The program will target elementary school students, providing curriculum and in-classroom education support along with a take-home kit that raises awareness about how individual actions and low-cost measures can provide significant reductions in electricity, natural gas and water consumption.

Residential Low Income Weatherization Program

The Residential Low Income Weatherization Program, which will be available to homeowners as well as renters with landlord approval, will provide assistance to low-income customers to reduce their energy consumption by installing energy efficient technologies and measures in their homes. In addition, NIPSCO is including a budget to allow for remediation of health and safety measures that impede the ability to complete weatherization. This could include warped door frames that impede effective door sealing, broken windows, or even a small hole in the roof that, once repaired, allows the weatherization work to be completed. NIPSCO is pleased to be able to offer this component to the program as it will decrease the number of homes for which weatherization previously could not be completed due to these issues. In addition, many of the repairs themselves will assist the customers in being more energy efficient, so it makes sense to include the repairs as part of the DSM program.

As a part of this program, NIPSCO is proposing to collaborate with Holistic Community Coalition, a 501(c)(3) organization in Lake County, Indiana, that has successfully developed its own program infrastructure to more effectively serve the low-income customers of Lake County. The organization hires individuals from the local area, gives them training in weatherization skills, and then utilizes these individuals to weatherize homes in the local area. The organization has a thorough communication plan whereby clients receive information prior to, during, and after the weatherization visit is completed. During the home visit, the technician will explain all of the steps a homeowner can take in being energy efficient as well as installing energy efficiency measures, which could include CFLs, pipe wrap and water saving devices. A few days after the home visit, there will be a follow up call to the client to see if they have any questions and to determine if they have any issues with any of the installed items. In addition to being a locally-based resource understanding the unique needs of the communities it serves, the Holistic Community Coalition has direct access to a large network of churches, which will assist the organization in reaching eligible customers. While this provides a unique outreach activity, customers do not need to be a member of any particular religion in order to participate in the program. The program will actively solicit senior citizen participation and promote the benefits of an energy efficient home. Additionally, because of the direct connection between a church and its congregation, a program that is actively promoted by the church leadership will likely lead to increased participation. As with its other programs, NIPSCO will have a thorough EM&V of the program, which will enable NIPSCO to assess the benefits of this program as well as possibly expand those benefits to its Low Income Weatherization program as a whole.

Residential Home Energy Assessment and Weatherization (“HEAW”) Program

The Residential HEAW Program will utilize a two-phase approach to capture savings in existing single-family homes. Phase I: Home Walk-through Energy Assessment – the implementation contractor will provide customers a one hour walk-through audit of their home and provide a report outlining opportunities to improve energy efficiency. The report will prioritize potential improvements, estimate their cost after incentives are applied and estimate the resulting energy cost savings and payback timeframe. The implementation contractor will also install appropriate low-cost measures, including CFLs, light emitting diode (“LED”) lamps, pipe wrap and water-saving devices as a part of the assessment. Phase II: Weatherization Services – the assessor will work with the customer to determine a schedule by which the program will follow-up to provide ongoing assistance with program offerings applicable to the customer. While the default schedule will be 30, 60, 90 and 180 days after the assessment, the follow ups will be tailored to suit individual needs. For example, the assessor may schedule eligible customers for duct sealing services within 30 days of the assessment and follow up to gain consent to proceed with insulation and air sealing after 60 days, as appropriate and agreed upon by each customer based on their individual needs. Customers will be able to choose from prequalified contractors, which will be selected based on their level of expertise, experience with previous implementation of NIPSCO’s Home Weatherization Program and itemized pricing for specified improvements. Utilizing a preapproved group of contractors to provide turnkey direct installation services will improve installation rates, while still allowing for customers to have choices. This provides a distinct customer benefit as the time and effort required to select and manage contractors is a key barrier to customers’ implementing improvements. Further, it will allow NIPSCO to closely manage customer service and quality control to ensure measures are properly installed. Under the new design the program administrator will be the same for both the home assessment and weatherization portions of the program. This should improve both the customer experience in terms of having a single point of contact as well as improve the efficiency of program delivery.

Residential Energy Efficiency Rebate Program

The Residential Energy Efficiency Rebate Program will influence the purchase and installation of high-efficiency heating and cooling technologies, through a combination of market push and pull strategies that stimulate demand while simultaneously increasing market provider investment in stocking and promoting high efficiency products. The electric program will promote premium efficiency air conditioners and heat pumps that have high-efficiency, electrically commutated motors (“ECMs”), ECM retrofits, air conditioner and heat pump tune ups, ductless heat pumps, heat pump water heaters and programmable thermostats.

Residential New Construction Program

The Residential New Construction Program will continue to recruit and educate selected builders and their trade allies on the benefits associated with energy-efficient homes and building practices designed to improve upon baseline efficiency. Builders will be provided with financial incentives to encourage the installation of premium-level efficient equipment and the use of better building techniques. As in NIPSCO’s current program, the incentives will be based on the overall efficiency of the home as indicated by the Home Energy Rating System (“HERS”) Score. The program will identify and recruit key builders who are not consistently (or seldom) building homes to meet the desired HERS Scores. Builders who choose to participate in the program will gain access to cash-back incentives designed to cover approximately 30 percent of the cost to upgrade and certify each home. In addition, they will be provided with personalized training on marketing energy efficiency to customers and energy efficient building standards.

Residential Home Energy Conservation Program

The Residential Home Energy Conservation Program is designed to significantly increase energy efficient behavior through increased customer engagement across a selected population within the NIPSCO service territory. Home Energy Reports are sent to a select population within the NIPSCO territory 1) to show large-scale, measurable and cost-effective energy savings over a one year period, 2) to increase program participation in select NIPSCO energy efficiency and DSM programs, and 3) to increase customer satisfaction through an improved customer experience. The Home Energy Report compares usage in one home that received the report to another comparable customer that did not receive the report (the control group). Any difference in usage over the same time period is counted as kWh savings for that particular period.

Air Conditioner (A/C) Cycling Program

The A/C Cycling Program is a voluntary program available to NIPSCO’s residential and C&I customers with air conditioning units of five tons or less. A load control switch is installed near the customer's central air conditioning unit. The radio-controlled switch allows NIPSCO to cycle the customer's air conditioning compressor on and off for short periods of time during peak demands. Cycling typically occurs on the hottest summer days during the week and events are not called on weekends or holidays. Participating customers receive a $10/month credit on their bills from June through September. NIPSCO is proposing to maintain and provide the incentive to the current customers in the program, but not offer new enrollments in 2015.

C&I Custom Program

The C&I Custom Program offers unique efficiency opportunities developed for the C&I customer through a custom approach for site specific measures and custom measures. Incentives are paid as $/kWh saved for site specific systems or equipment efficiency improvements.

C&I Prescriptive Program

The C&I Prescriptive Program is designed to assist C&I customers in reducing electric energy consumption and costs. The program provides monetary incentives for specific measures based on the installation of energy efficient equipment upgrades such as energy efficient light fixtures and ballasts as well as energy efficient pumps, motors and variable speed drives.

C&I Small Business Direct Install Program

The C&I Small Business Direct Install Program is used to penetrate the small commercial customer market based on evidence that small commercial customers do not have the expertise, time, or available capital to make energy efficiency upgrades. This direct install approach of measures including lighting and water saving measures virtually eliminates the barriers of participant hassle and search costs. An added benefit of the program is that it introduces this market to other program offerings and encourages them to pursue additional energy efficiency investments through the Prescriptive and Custom programs.

School Audit Direct Install Program

The School Audit Direct Install Program is currently offered as a Core program and has been highly successful in NIPSCO's service territory. It is designed to educate school officials on the benefits of energy efficiency and the savings associated with the installation of recommended energy saving measures and operational improvements as well as providing the direct installation of certain measures. At the conclusion of the energy assessment, the school is presented with a detailed report that demonstrates ways to save energy and money through potential incentive dollars that may be available from other NIPSCO program offerings. The direct install measures will include items such as vending machine controllers, CFLs, occupancy sensing power strips and lighting occupancy sensors.

The 2015 projected energy savings are summarized by program in Table 5-12.

Table 5-12
2015 Projected Energy and Demand Savings (MWh/kW)

Program	Savings
Residential Programs	
Residential Lighting Program	11,137/7,731
Residential Elementary Education Program	5,194/2,750
Residential Low Income Weatherization Program	648/178
Residential Home Energy Audit and Weatherization Program	5,426/2,269
Residential Energy Efficiency Rebate Program	2,220/579
Residential New Construction Program	857/234
Residential Home Energy Conservation Program	24,000/6,193
Total Residential Programs	**49,482/19,934**
C&I Programs	
C&I Custom Program	14,000/1,641
C&I Prescriptive Program	50,000/7,670
C&I Small Business Direct Install Program	6,000/933
School Audit Direct Install Program	121/31
A/C Cycling Program (Residential and C&I)	0/17,184
Total C&I Programs	**70,121/27,459**
Total 2015 Electric DSM Program	**119,603/47,393**

The NIPSCO DSM 2015 avoided cost is $7,701,016 with participant bill reduction of $60,659,406, participant incentive of $8,820,004, program cost borne by participant of $16,218,052. NIPSCO DSM has a negligible impact on T&D requirements based on the 2015 program plan. The proposed 2015 DSM program designs and projected savings are not final; however NIPSCO does not expect them to change drastically.

2016-2035 DSM Resources

NIPSCO engaged the services of Applied Energy Group ("AEG") to identify the DSM measures that would be appropriate for the NIPSCO territory based on census information, population growth, age of the housing stock, and potential technology existing today and in future, potential savings associated with these various measures and then assess the likely level of participation. The results of the DSM study are included in Appendix G.

NIPSCO then had these various measures input into the DSMore Model to start the screening process. An initial screen of each of these measures was performed through assessing the benefits (or avoided costs) against the costs of the measure. As such, if the benefits of a measure did not outweigh the costs, the measure was dropped from consideration.

As measures pass the initial screen, they were then aggregated by end use (heating, cooling, lighting) and then by sector (residential, commercial, and industrial). See Table 5-13.

Table 5-13
End Use Measures Aggregated by Sector

Measures	Residential	Commercial	Industrial
Appliances	✓		
Cooling	✓	✓	✓
Electronics	✓		
Exterior Lighting	✓	✓	✓
Food Preparation		✓	
Heating		✓	✓
Interior Lighting	✓	✓	✓
Miscellaneous	✓	✓	✓
Motors			✓
Office Equipment		✓	
Process			✓
Refrigeration		✓	
Space Heating	✓		
Ventilation		✓	✓
Water Heating	✓	✓	

These aggregated end use sectors (comprised of various measures) were then run through the industry standard tests to determine whether they would pass the initial screen of Total Resource Cost ("TRC") test and Utility Cost Test ("UCT") scores. These tests are described in greater detail in Table 5-14. The following table shows the results of the standard DSM tests. It is important to note that the DSM forecast was completed using the assumption that no industrial customers would elect to opt out of the program as provided for in SEA 340.

Table 5-14
DSM Standard Test Results

Description	Utility Test	TRC Test	RIM Test	Societal Test	Participant Test
Residential HVAC	1.33	1.03	0.90	2.35	1.06
Residential Lighting	2.70	2.78	0.70	4.19	5.76
Residential Other	1.86	1.47	0.78	2.62	3.11
C&I HVAC	2.09	1.68	0.98	5.27	1.84
C&I Lighting	4.65	3.50	0.86	10.20	4.31
C&I Other	5.96	4.79	0.92	13.14	6.63
C&I Process	3.08	2.38	0.66	6.72	4.48

The 2016-2035 projected cumulative savings (MWh) for aggregated end use sectors are in Table 5-15.

Table 5-15
Projected Cumulative Savings (MWh)

Energy Savings (MWh)	Residential Lighting	Residential HVAC	Residential Other	C&I Lighting	C&I HVAC	C&I Other	C&I Process	Total
2016	29,067	1,441	28,236	28,194	13,050	19,741	36,904	156,633
2017	38,863	2,724	31,088	40,742	19,309	30,285	54,774	217,785
2018	48,200	4,183	33,929	53,308	25,637	40,732	72,579	278,568
2019	57,095	5,981	36,354	66,080	32,289	50,026	90,370	338,195
2020	74,585	7,963	41,396	117,435	40,525	57,596	108,340	447,840
2021	70,185	10,035	45,600	162,754	49,034	62,605	126,362	526,575
2022	74,877	12,261	50,031	206,154	57,676	67,459	144,435	612,893
2023	76,619	14,588	59,716	247,372	66,257	71,944	162,339	698,835
2024	77,395	17,067	67,391	290,250	77,072	76,910	180,649	786,734
2025	79,373	19,463	75,297	329,740	87,376	81,647	197,633	870,529
2026	89,386	21,958	83,701	369,559	98,354	86,574	215,141	964,673
2027	98,540	24,446	91,349	410,838	110,007	91,269	232,505	1,058,954
2028	107,821	27,000	98,697	451,652	121,356	96,304	250,422	1,153,252
2029	116,462	29,240	106,480	490,263	132,421	98,942	266,724	1,240,532
2030	125,689	31,446	114,844	524,850	142,669	98,729	283,732	1,321,959
2031	134,663	33,477	125,240	558,239	152,563	97,136	300,738	1,402,056
2032	126,743	35,825	134,812	593,634	162,514	97,004	318,580	1,469,112
2033	123,038	37,503	143,362	625,695	171,804	96,902	334,318	1,532,622
2034	117,410	38,974	150,649	669,642	180,711	97,970	350,819	1,606,175
2035	115,426	39,598	157,209	668,463	189,627	100,976	367,222	1,638,521

The 2016-2035 projected annual costs (2014$) for aggregated end use sectors are in Table 5-16.

Table 5-16
Projected Annual Costs (2014$)

Annual Cost ($)	Residential Lighting	Residential HVAC	Residential Other	C&I Lighting	C&I HVAC	C&I Other	C&I Process	Total
2016	3,301,684	1,228,665	1,528,217	1,287,340	4,899,486	1,840,409	4,258,084	18,343,885
2017	2,508,296	1,357,422	1,587,080	1,293,466	5,053,184	1,682,125	4,035,206	17,516,779
2018	1,849,945	1,521,550	1,643,260	1,463,205	5,292,571	1,616,695	4,280,492	17,667,718
2019	1,219,373	2,332,519	1,749,690	1,584,542	5,706,452	1,472,088	4,371,859	18,436,523
2020	4,865,527	2,559,081	2,354,072	14,892,185	6,911,839	1,186,702	4,476,899	37,246,305
2021	4,035,520	2,821,753	3,997,463	13,148,449	7,949,195	1,281,942	8,301,434	41,535,756
2022	4,705,344	3,121,698	4,348,369	12,658,755	8,343,122	1,328,793	7,962,242	42,468,323
2023	3,570,287	3,382,760	7,771,783	13,046,498	8,582,853	1,339,276	8,180,183	45,873,640
2024	3,116,422	3,672,072	8,857,828	13,805,456	10,348,900	1,403,658	8,520,962	49,725,298
2025	3,645,556	4,042,594	9,462,911	13,514,775	15,152,106	1,511,272	9,716,210	57,045,424
2026	3,370,450	4,537,454	10,845,520	13,694,885	15,767,948	1,475,087	13,808,065	63,499,409
2027	3,156,929	4,881,366	10,577,767	15,046,771	17,295,507	1,451,663	13,719,650	66,129,653
2028	3,184,809	5,305,169	10,363,933	15,031,597	17,791,531	1,717,528	13,983,025	67,377,592
2029	3,252,132	5,684,432	12,076,131	15,929,474	19,882,425	1,857,478	14,282,222	72,964,294
2030	3,445,172	6,090,423	12,982,234	16,262,481	21,236,963	1,949,601	17,419,115	79,385,989
2031	3,440,036	6,605,389	17,037,540	17,345,938	21,182,834	2,014,397	22,000,918	89,627,052
2032	3,539,420	8,379,569	16,086,813	17,946,256	21,890,078	2,474,925	21,825,268	92,142,329
2033	4,294,899	8,932,202	16,719,756	18,470,942	22,283,546	2,472,575	22,495,269	95,669,189
2034	4,113,268	9,567,661	17,493,127	24,476,430	24,001,405	2,689,847	22,946,820	105,288,558
2035	4,125,549	8,968,963	17,878,726	22,463,913	31,423,633	2,894,917	24,752,489	112,508,190

Avoided costs account for energy, capacity, T&D and ancillary. The annual avoided cost calculation include: 1) the cost-based proxy for electric generation capacity (annualized $/kW) multiplied by the expected annual demand savings attributed to each measure adjusted by the applicable future year escalation factor; 2) estimated transmission capacity cost ($/kW) multiplied by the expected annual demand savings attributed to each measure adjusted by the applicable future year escalation factor; 3) estimated distribution capacity cost ($/kW) multiplied by the expected annual demand savings attributed to each measure adjusted by the applicable future year escalation factor; 4) estimated annual average energy cost ($/kWh) multiplied by the expected annual energy savings attributed to each measure adjusted by the applicable future year escalation factor; and 5) estimated MISO Ancillary Charges ($/kWh) multiplied by the expected annual energy savings attributed to each measure adjusted by the applicable future year escalation factor. See Tables 5-17 through 5-19 for avoided cost calculation assumptions. See Table 5-20 for 2016-2035 projected cumulative avoided costs.

Table 5-17
Avoided Cost Assumptions

Discount Rates	
Electric Utility Discount Rate (%)	6.54%
Gas Utility Discount Rate (%)	6.40%
Real Discount Rate (%)	2.72%
Participant Discount Rate (%)	15.00%
Participant Income/Sales Tax Rate (%)	7.00%
System Losses	
Residential Electric Losses (%)	2.97%
Residential Peak Electric Losses (%)	4.11%
Commercial Average (Primary & Secondary) Electric Losses (%)	2.65%
Industrial Electric Losses (%)	1.65%
Industrial Peak Electric Losses (%)	2.41%
Gas Losses (%)	0.08%
Electric Generation Capacity Cost (Summer)	
Cost-Based Proxy for Electric Generation Capacity (Annualized $/kW)	$82.38
Coincident Month (1-12)	7
Coincident Hour (1-24)	14
Supplemental Reserve Margin (%) / MISO Planning Reserve Margin before EFOR	6.20%
Transmission & Distribution Capacity Cost	
Distribution ($/kW)	$30.85
Transmission ($/kW)	$21.40
Energy Cost	
Annual Average ($/kWh)	$0.0346
Annual MISO Peak Hours (%)	47.6%
Annual MISO Off-Peak Hours (%)	52.4%
Annual Average Gas ($/Therm)	$0.46

Table 5-18
MISO Ancillary Charges for Avoided Cost Calculations

Month	Avoided MISO Ancillary Charges ($/kWh)
Jan	$0.0030
Feb	$0.0033
Mar	$0.0034
Apr	$0.0042
May	$0.0036
Jun	$0.0029
Jul	$0.0023
Aug	$0.0023
Sep	$0.0028
Oct	$0.0038
Nov	$0.0026
Dec	$0.0025

Table 5-19
Applicable Future Year Escalation Factor Adjustment for Avoided Cost Calculations

Year	Electric Base Rates	Electric Fuel Cost Factor	Electric Avoided Capacity Cost	Electric Avoided T&D Cost	Electric Avoided Energy Cost	Electric MISO Ancillary Market	Gas Rates	Gas Capacity Cost	Gas Fuel and Supply Cost (EIA)
2013	1.0150	1.0000	1.0150	1.0150	1.2373	0.9405	1.0184	1.0000	1.0184
2014	1.0303	0.9841	1.0303	1.0303	1.1193	1.0000	1.0425	1.0000	1.0425
2015	1.0472	1.0480	1.0472	1.0472	0.7419	1.0018	1.0829	1.0000	1.0829
2016	1.0675	1.0818	1.0675	1.0675	1.0000	1.0801	1.1041	1.0000	1.1041
2017	1.0875	1.1209	1.0875	1.0875	1.1035	1.1584	1.1261	1.0000	1.1261
2018	1.1082	1.1597	1.1082	1.1082	1.1694	1.2027	1.1519	1.0000	1.1519
2019	1.1291	1.1937	1.1291	1.1291	1.2353	1.2486	1.1920	1.0000	1.1920
2020	1.1512	1.4048	1.1512	1.1512	1.3188	1.2963	1.2396	1.0000	1.2396
2021	1.1739	1.4668	1.1739	1.1739	1.4080	1.8647	1.2915	1.0000	1.2915
2022	1.1962	1.5435	1.1962	1.1962	1.5034	1.9635	1.3420	1.0000	1.3420
2023	1.2189	1.6550	1.2189	1.2189	1.7681	2.0676	1.3944	1.0000	1.3944
2024	1.2425	1.7488	1.2425	1.2425	1.8529	2.1772	1.4462	1.0000	1.4462
2025	1.2667	1.8442	1.2667	1.2667	1.9419	2.2926	1.5014	1.0000	1.5014
2026	1.2919	1.9320	1.2919	1.2919	2.0353	2.4142	1.5374	1.0000	1.5374
2027	1.3182	1.9980	1.3182	1.3182	2.1331	2.4950	1.5743	1.0000	1.5743
2028	1.3441	2.0555	1.3441	1.3441	2.2356	2.5786	1.6121	1.0000	1.6121
2029	1.3709	2.3099	1.3709	1.3709	2.2991	2.6651	1.6508	1.0000	1.6508
2030	1.3985	2.4081	1.3985	1.3985	2.3644	2.7547	1.6904	1.0000	1.6904
2031	1.4276	2.4983	1.4276	1.4276	2.4316	2.8474	1.7310	1.0000	1.7310
2032	1.4574	2.5961	1.4574	1.4574	2.5007	2.9433	1.7725	1.0000	1.7725
2033	1.4886	2.7096	1.4886	1.4886	2.5717	3.0427	1.8151	1.0000	1.8151
2034	1.5214	2.8226	1.5214	1.5214	2.6448	3.1455	1.8586	1.0000	1.8586
2035	1.5538	2.9404	1.5538	1.5538	2.7200	3.2519	1.9032	1.0000	1.9032

Table 5-20
Projected Avoided Costs for DSM 2016-2035 (2014$)

End Use Sector	C&I HVAC	C&I Lighting	C&I Other	C&I Process	Residential HVAC	Residential Lighting	Residential Other
2016	1,881,601	1,789,894	1,209,529	2,769,380	452,098	1,578,922	2,689,937
2017	2,551,065	2,088,750	1,482,954	3,555,944	762,236	1,649,404	2,454,425
2018	3,648,530	3,258,093	2,386,165	5,486,026	1,175,037	2,501,187	2,885,496
2019	4,744,461	4,348,147	3,162,031	7,316,469	1,637,995	3,218,754	3,167,273
2020	5,979,524	7,819,459	3,801,698	9,131,220	2,137,157	4,402,563	3,635,449
2021	7,306,657	11,241,461	4,344,116	11,119,033	2,674,878	4,354,006	4,037,964
2022	8,744,580	14,903,594	4,938,385	13,297,452	3,265,262	4,901,428	4,515,195
2023	10,674,772	20,501,203	6,056,460	16,773,608	3,981,199	5,832,056	5,803,017
2024	12,575,511	25,286,357	6,828,495	19,531,603	4,705,644	6,223,439	6,749,129
2025	15,030,106	32,188,765	8,121,312	23,538,096	5,645,839	7,196,076	8,164,760
2026	17,217,342	37,691,125	9,009,398	26,682,269	6,678,808	8,490,392	9,333,361
2027	19,608,003	43,788,417	9,938,193	30,031,706	7,613,621	9,807,096	10,535,146
2028	22,094,443	50,195,183	10,943,929	33,604,814	8,643,689	11,214,244	11,808,485
2029	24,668,174	56,830,942	11,749,283	37,242,711	9,749,893	12,654,399	13,236,752
2030	27,245,032	63,312,839	12,230,295	41,092,939	10,964,817	14,229,054	14,820,033
2031	29,693,066	69,272,510	12,416,376	44,753,471	12,200,452	15,694,879	16,599,901
2032	32,259,931	75,575,084	12,750,244	48,566,537	13,574,322	15,166,738	18,347,684
2033	34,893,117	82,185,483	13,169,379	52,543,626	14,922,265	15,200,328	20,158,965
2034	37,547,894	90,464,604	13,723,055	56,682,037	16,369,655	14,935,910	21,887,903
2035	40,346,452	92,999,643	14,569,368	61,000,220	17,723,264	15,119,173	23,641,881

See Table 5-21 for 2016-2035 projected number of participants. These participation numbers represent customer adoption of economic DSM measures.

Table 5-21
Cumulative Participants for 2016-2035 (Net)

End Use Sector	C&I HVAC	C&I Lighting	C&I Other	C&I Process	Residential HVAC	Residential Lighting	Residential Other
2016	1,313	186,539	31,321	3,843	8,568	1,071,243	243,811
2017	1,964	284,518	49,119	5,621	14,490	1,435,376	262,347
2018	2,635	378,907	64,702	7,395	21,119	1,780,243	282,757
2019	3,328	476,149	76,393	9,183	29,072	2,108,178	301,784
2020	4,274	1,620,283	79,161	10,970	37,250	2,872,952	337,892
2021	5,234	2,636,569	80,661	13,269	47,809	2,820,824	360,125
2022	6,213	3,605,090	82,048	15,485	57,081	3,124,232	383,772
2023	7,199	4,531,929	83,385	17,687	66,736	3,280,818	448,468
2024	8,209	5,631,681	84,986	19,878	76,761	3,379,292	478,007
2025	9,231	6,523,059	86,660	22,042	86,976	3,584,602	502,970
2026	10,286	7,391,658	88,394	24,209	97,318	4,068,812	531,421
2027	11,414	8,283,656	90,052	26,366	108,170	4,514,203	558,262
2028	12,604	9,143,499	91,653	28,511	119,470	4,953,572	584,324
2029	13,827	10,011,170	93,102	30,646	132,519	5,392,183	611,000
2030	14,981	10,754,502	84,681	32,755	145,972	5,845,313	639,787
2031	16,120	11,481,051	68,635	34,871	159,928	6,290,653	672,522
2032	17,290	12,210,564	54,687	36,978	176,240	5,972,695	702,788
2033	18,461	12,953,895	43,143	39,074	190,434	5,877,473	733,410
2034	19,602	13,938,210	35,552	41,162	205,369	5,665,100	763,562
2035	20,768	13,737,495	36,981	43,241	218,611	5,592,402	792,328

Strategies to Capture Lost Opportunities

In the Order for IURC Cause No. 43912, the Commission authorized NIPSCO to recover the costs associated with its approved Core and Core Plus programs through the Demand-Side Management Adjustment ("DSMA") Rider. NIPSCO makes semi-annual filings for factors to be effective January through June and July through December of each year. These filings will reflect estimated costs and DSMA Factors and recovery occurs over a six-month period which coincides with the estimation period. Reconciliation to actual expenditures is made in a subsequent semi-annual filing. In August 2012, the Commission issued an Order in IURC Cause No. 44154 approving NIPSCO's request for approval for the recovery of lost margins through its DSMA filings.

Calculation of Lost Margins

In determining the forecasted measures that are to be installed in a given time period on a go-forward basis, NIPSCO assumes that the measures will be installed, and therefore the associated energy and demand savings achieved evenly over the 12 months of each calendar year. A reduction of any savings from measures that were installed longer than their identified measure life will be removed from the cumulative savings as well. Cumulative measure savings will be reset to zero as of the test year in NIPSCO's next electric rate case. For deemed savings, NIPSCO uses the actual (evaluated and unevaluated) installed measures to determine the deemed net energy and net demand savings and then utilizes the forecasted deemed net energy and demand savings as approved by its Oversight Board[2]. NIPSCO ultimately reconciles the projected net energy and net demand savings with the actual deemed savings from actual installed measures. The projected net energy and net demand savings are also reconciled again once the EM&V results are received for the Program Year in question. The evaluated deemed savings, verified measure installations and evaluated net to gross ratios will be applied retroactively to the original projected savings figures for the purposes of reconciling lost margins.

NIPSCO's current electric rates are used to calculate the projected lost margins. With the exception of Rate 632, the tail block (lowest energy rate) is used to calculate the lost margins for reduced energy. The middle block rate was used for Rate 632 since this rate uses an inverted energy rate block structure. Lost margins for net demand reduction assume each customer is on the transmission (or lowest) demand charge for each rate. Lost margins associated with reduced net energy also reflect the reduction of the energy rate by the variable operations and maintenance ("O&M") expense for generation expenses that was used to compute NIPSCO's current rates.

Cost-Benefit Components

All DSM Core Plus programs are evaluated for consideration of inclusion in the IRP using the DSMore software and must be cost-effective based on the TRC test.

DSMore, developed by Integral Analytics, is a modeling tool for EE and DSM that correlates weather, loads and prices on an hourly level. The DSMore application is unique in that it values DSM/ EE using a risk-based approach. The relationship between prices and loads is captured at the hourly level (8760) to accurately measure the risk-based DSM value. Some of the advantages of DSMore include:

- Provides all standard cost-effectiveness tests, plus long-run option value test.
- Aligns prices and loads at hourly level, by day-type, month, leap years, holidays, etc., and by region.
- Customizes avoided costs to specific customer load shapes and unique weather sensitivities.
- Supports gas and electric programs, numerous rates and program types including conservation, demand response, customer sited renewables and electric vehicles.
- Provides summary financial reports, and aggregations, including accurate weather normal lost revenues and shared savings.

NIPSCO focused on the following five common cost-effectiveness tests to examine the measure from different perspectives:

Utility Cost Test ("UCT") or Program Administrator Cost ("PAC") Test

This test includes the energy costs and benefits that are experienced by the energy efficiency program administrator. This test is most consistent with the way that supply-side resources are evaluated by vertically integrated utilities. The costs include all expenditures by the program administrator to design,

[2] The NIPSCO Oversight Board is comprised of NIPSCO, the Office of Utility Consumer Counselor, the Citizens Action Coalition, Inc. and the NIPSCO Industrial Group.

plan, administer, deliver, monitor and evaluate efficiency programs offset by any revenue from the sale of freed up energy supply. The benefits include all the avoided utility costs, including avoided energy costs, avoided capacity costs, avoided transmission and distribution costs, and any other costs incurred by the utility to provide electric.

$$Utility\ Test = \frac{Avoided\ Costs}{Utility\ Costs}$$

TRC Test

This test includes the costs and benefits experienced by all utility customers, including both program participants and nonparticipants. The costs include all the costs incurred by the program administrator and participating customer, including the full incremental cost of the efficiency measure, regardless of whether it was incurred by the program administrator or the participating customers. The benefits include all the avoided utility costs, plus any other program benefits experienced by the customers, such as avoided water costs, reduced operations and maintenance costs, improved comfort levels, health and safety benefits, and more.

$$TRC\ Test = \frac{Avoided\ Costs + Tax\ Saved}{Utility\ Costs + Participant\ Costs\ Net\ of\ Incentives}$$

Ratepayer Impact Measure ("RIM") Test

This test provides an indication of the impact of energy efficiency programs on utility rates. The results of this test provide an indication of the impact of energy efficiency on those customers that do not participate in the energy efficiency programs. The costs include all the expenditures by the program administrator, plus the lost revenues to the utility as a result of the inability to recover fixed costs over fewer sales. The benefits include the avoided utility costs.

$$RIM\ Test = \frac{Avoided\ Costs}{Utility\ Costs + Lost\ Revenue}$$

Societal Cost Test

This test includes the costs and benefits experienced by all members of society. The costs include all of the costs incurred by any member of society: the program administrator, the customer, and anyone else. Similarly, the benefits include all of the benefits experienced by any member of society. The costs and benefits are the same as for the TRC Test, except that they also include externalities, such as environmental costs and reduced costs for government services.

$$Societal\ Test = \frac{Avoided\ Costs + Tax\ Saved + Environmental + Other}{Utility\ Costs + Participant\ Costs\ Net\ of\ Incentives}$$

Participant Test

This test includes the costs and benefits experienced by the customer who participates in the efficiency program. The costs include all the direct expenses incurred by the customer to purchase, install, and operate an efficiency measure. The benefits include the reduction in the customer's electricity bills, as well as any financial incentive paid by the program administrator.

$$Participant\ Test = \frac{Lost\ Revenue + Incentives + Tax\ Savings}{Participant\ Costs}$$

Cost-Benefit Analysis

Table 5-22 summarizes the portfolio results for the total portfolio, Residential and C&I programs.

Table 5-22
Benefit Cost Analysis
NIPSCO 2015 Proposed DSM Electric Programs

	Utility Test	TRC Test	RIM Test	Societal Test	Participant Test
Benefit Cost Analysis					
NIPSCO DSM Electric C&I Portfolio	3.94	2.66	0.67	3.24	3.57
NIPSCO DSM Electric Residential Portfolio	1.69	1.71	0.63	2.05	5.31
NIPSCO DSM Electric Portfolio	2.76	2.34	0.64	2.81	4.28

Demand Response – Interruptible Service

On December 21, 20111, the IURC issued an Order Cause No. 43969 approving Electric Service Tariffs which included Interruptible Industrial Service Rider 675. Rider 675 is available to customers taking service under Rate 632, Rate 633 or Rate 634. NIPSCO held an open enrollment for available capacity under Rider 675 with eligible customers while affording the first offering of interruptible capacity to customers whom were already contracted for interruptible capacity under previous contracts. The total capacity made available under this Rider was limited to 500 MW and the total sum of credits could not exceed $38,000,000 in any calendar year. All requests for capacity had to be 1,000 kW or greater. Eligible customers were contacted and asked for the amount of interruptible capacity and options for which they were willing to contract. All requests were considered according to length of notice to interrupt or curtail (option) with the first allocation going to the shortest notification time and then to the next shortest notification time (Option D, C, B, A). Allocations were finished when the $38,000,000 annual credit was reached. At that time NIPSCO had contracted with eligible customers for a total of 377,082 kW of Rider 675 capacity.

The Interruptible Contract Demand is the demand (kW) that the customer makes available for Interruptions and/or Curtailments from one or more of the customers' premises taking service under Rate 632, Rate 633 or Rate 634. Customers taking service under this Rider specify a Firm Contract Demand that they intend to exclude from interruptions or curtailments. Customers who contracted for this service are required to interrupt or curtail at the stated notice by NIPSCO and the provisions of service under this Rider to Customers require they meet the applicable Load Modifying Resource requirements pursuant to MISO Tariff Module E or its successor. NIPSCO registered all 377,082 kW Rider 675 capacity with MISO[3].

NIPSCO also has an interruptible service for residential, commercial and industrial customers through the A/C Cycling program. NIPSCO started marketing this program in November of 2011. Actual cycling began in the summer of 2012. This program has the ability to reduce peak load by cycling residential, commercial and industrial air conditioning units during times of peak demand.

Customer Distributed Generation

Introduction

NIPSCO's FIT pilot was approved on July 13, 2011, and implementation began immediately as a three-year pilot program with a 30 MW capacity cap. The FIT offers a pilot rate greater than the retail electric rate in the current approved sales tariffs that provides an incentive to encourage development of renewable generating resources. The pilot program is designed to help maximize the development of renewable energy in Indiana, and includes biomass, wind and solar resources.

The FIT tariff pilot program provides the customer a sell-back opportunity to NIPSCO at a predetermined price for up to 15 years through a Renewable Purchase Power Agreement ("RPPA"). Participating customers receive a cash payment from NIPSCO for the amount of electricity generated and delivered to NIPSCO through an approved interconnection and metering point.

Additional program details:

- The participating generator must be an existing NIPSCO electric customer.
- Installation must be wind, solar, and new hydroelectric or sustainable biomass projects.
- FIT is available to all NIPSCO electric customers.
- Supports generation projects with a generating nameplate capability from 5kW-5MW.
- A Interconnection Agreement (IA) and RPPA is required to reserve capacity or enter the Queue under the FIT, Rate 665 structure.

[3] On March 14, 2014, FERC conditionally approved MISO Docket ER14-990-000 with an Order which provides that Load Modifying Resources, such as Interruptible Demand, will be treated as Capacity Resources, effective March 15, 2014. Further, in converting the Load Modifying Resource to a Capacity Resource, it is to retain its current value in satisfying resource adequacy requirements. Therefore, the Load Modifying Resource value is grossed-up by Planning Reserve Margin and the Transmission Losses, since such resources have neither transmission losses, nor forced outages. As such, the 377 MW of Load Modifying Resources that NIPSCO had in the summer of 2013, becomes 412 MW of Capacity Resources in the summer of 2014, without any change in the actual resources.

- The customer is responsible for interconnection fees and installation costs per the Indiana Administrative Code.
- The customer is responsible for maintenance and proper operation of the generating device in a safe manner consistent with interconnection agreement.
- Customer projects are classified into small solar and wind, and large wind, solar, biomass and new hydro.
- Each classification receives payment for the amount of energy generated per approved Rate 665:
  - Wind ≤ 100kW: $0.17/kWh
  - Wind 101kW-2MW: $0.10/kWh
  - Solar 5 kW ≤ 10kW: $0.30/kWh
  - Solar 11kW-2MW: $0.26/kWh
  - Biomass ≤ 5MW: $0.106/kWh
  - New hydro ≤ 1MW: $0.12/kWh

Participation

The following tables summarize the customer participation in the FIT as of July 31, 2014. Table 5-23 lists, by technology and size segment, the generation approved, connected and operating.

Table 5-23
FIT Project Status

Technology	In-Service Projects (kW)	In Construction (kW)	Total FIT (kW)
Biomass	9,320	5,030	14,350
Solar (large)	14,500	0	14,500
Solar (small)	690	10	700
Wind (large)	150	0	150
Wind (small)	10	0	10
New Hydro	0	0	0
Total	**24,670**	**5,040**	**29,710**

Table 5-24 lists all applications that did not get approved for participation in the FIT as of July 31, 2014. These projects can move forward if they were to elect to utilize the small power producer co-generation tariff that is currently approved and available to these proposed generating projects.

Table 5-24
Pending FIT Application (not approved)

Technology	Pending Applications - not in service/ queue (kW)
Biomass (large)	7,290
Solar (large)	25,986
Solar (small)	60
Wind (large)	1,100
Wind (small)	0
New Hydro	0
Total	**34,436**

Total metered generation for projects that have interconnected and have begun selling energy to NIPSCO is 73,898,289 kWh through December 31, 2013. Table 5-25 below shows the annual production and growth by technology segment.

Table 5-25
Annual Production by Technology - Generation (kWh)

Technology	2011	2012	2013	Total	% Total
Small Solar	-	118,895	471,806	590,701	0.8%
Large Solar	-	433,758	15,789,457	16,223,214	22.0%
Small Wind	-	3,588	15,721	19,310	0.0%
Large Wind	-	-	90,113	90,113	0.1%
Biomass	6,219,791	19,152,432	31,602,728	56,974,951	77.1%
Total	**6,219,791**	**19,708,672**	**47,969,825**	**73,898,289**	**100.0%**

Table 5-26 has the projected annual output for FIT renewable energy generation when all customers either in-service or under construction are connected and selling energy to NIPSCO. Energy generated from biomass resources makes up approximately 79 percent of the projected renewable generation from FIT generators, while 19.8 percent of total FIT generation is projected to be generated from large solar generators.

Table 5-26
Forecasted FIT Generation by Technology

Technology Type	Capacity Final (kW)	Annual Production (kWh)	Technology Capacity Factor	Renewable Generation (%)
Solar Small	700	822,268	13.4%	0.7%
Wind Small	10	8,067	9.0%	0.0%
Wind Large	150	270,339	20.6%	0.2%
Solar Large	14,500	22,409,495	17.6%	19.8%
Biomass	14,350	89,706,220	71.4%	79.2%
Total	**29,710**	**113,216,390**	**-**	**100.0%**
Unsubscribed	290			
Total Capacity	**30,000**			

FIT – Phase II

NIPSCO's current electric Rate 665 – Renewable Feed-In Tariff offers an option, on a pilot basis, aimed at promoting further renewable generation opportunities in Northern Indiana and responding to customers' interest in powering their homes and businesses with renewable energy projects. The pilot program has a total non-dispatchable capacity available of 30 MW. As of October 14, 2014, 24.67 MW of generation is in service. The generation in service is listed in Table 5-27.

Table 5-27
FIT – Phase II Generation in Service

Technology	MW
Biomass (large)*	9.32
Solar (large)*	14.50
Solar (small)*	0.69
Wind (large)*	0.15
Wind (small)*	0.0102
New Hydro	0.00
Total	**24.6702**

**large represents project size of 11 kW - 5000 kW*
**small represents project size of 5 kW - 10 kW*
**5.030 MW Biomass (large) is currently in queue*

On October 9, 2014, the Stipulation and Settlement Agreement between NIPSCO, the Indiana Office of Utility Consumer Counselor, Citizens Action Coalition of Indiana, Inc., the Hoosier Chapter of the Sierra Club, Indiana Distributed Energy Alliance, Inc., and Bio Town Ag, Inc. in IURC Cause No. 44393 was filed. The settlement proposes to provide an additional 16 MW of capacity available for smaller renewable projects.

Electric Vehicle Programs (Phase I and Phase II):

NIPSCO IN-Charge Electric Vehicle Program – At Home (Phase I)

On February 1, 2012, the Commission issued an Order in Cause No. 44016 approving NIPSCO's IN-Charge Electric Vehicle ("EV") Pilot Program. Approximately two months after Commission approval, on April 2, 2012, NIPSCO launched its IN-Charge Electric Vehicle Program - At Home. As of July 31, 2014, NIPSCO had received 221 customer enrollment requests. Of these 221 requests, 138 have gone well beyond the initial inquiry. Of these 138, home charger and second meter installations have been completed for 127 customers and an additional 11 customers are moving forward with scheduling installations. Estimates for installation costs, including the cost of a home EV charger, ranged from $667 to $5,153 with an average of $1,959. The average incentive amount used by customers with completed installations was $1,622.

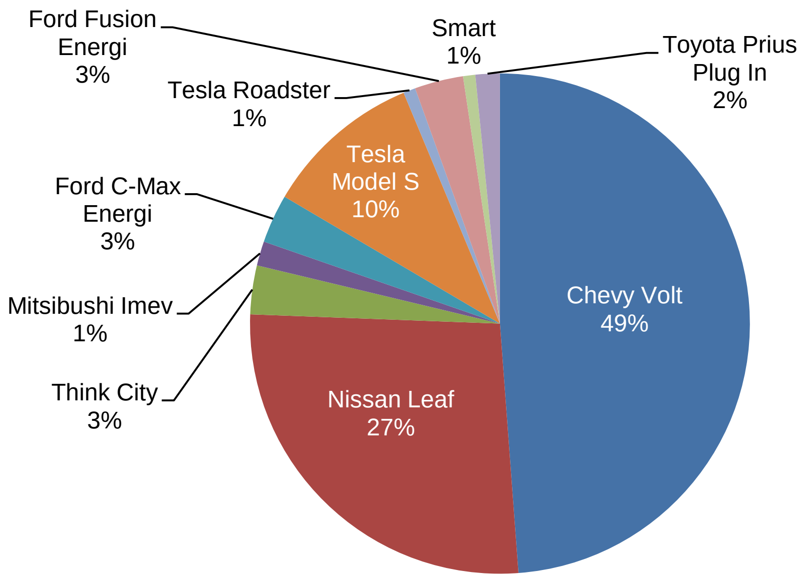
A detailed customer request status breakdown as of July 31, 2014 is provided in Table 5-28.

Table 5-28
NIPSCO's IN-Charge Electric Vehicle Program - At Home
(Status Summary as of July 31, 2014)

Meter Installation Process	Completed	127
	In Scheduling Process	4
Home Charger Installation Process	Completed & Waiting on Customer to Proceed	1
	In Scheduling Process	6
Site Survey Process	Survey Completed - Waiting on More Information from Customer	13
	In Scheduling Process	17
Enrollment Process	Waiting for Customer Response to Complete Online Survey	3
	Requested to be Recontacted at Later Date	1
	General Inquiry	9
	Decided Not to Proceed	20
	Customer Not Qualified	20
	Waiting on NIPSCO	0
Total Requests to Enroll		**221**

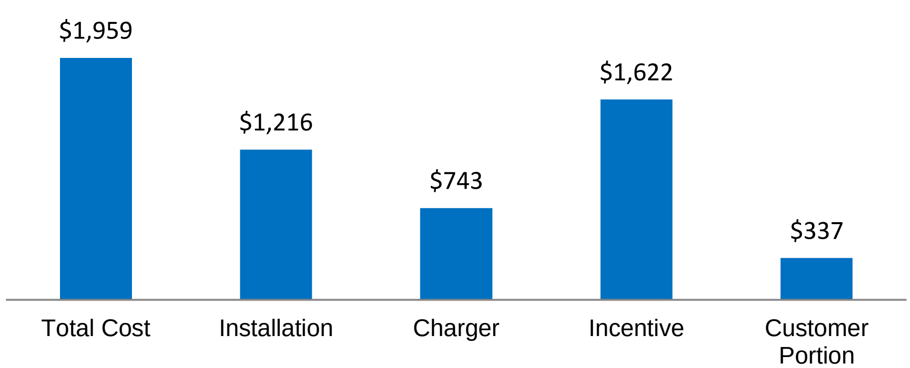
A breakdown of the type of electric vehicles purchased by the 1,270 customers who have completed the entire process is provided below in Figure 5-3.

Figure 5-3
Type of Vehicle Purchased



The average cost to install a Level II home charging station during the pilot was just over $1,950. A cost breakdown for the home charging station from the pilot is provided in Figure 5-4.

Figure 5-4
Average Home Charging Installation

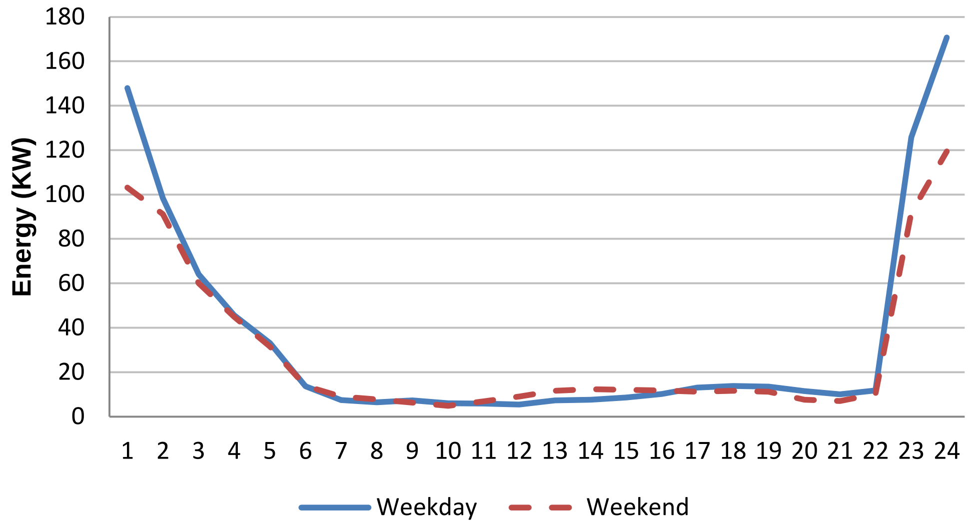


On average, EV customers use approximately 206 kWh per month charging their electric vehicle. The actual amount of consumption, however, will vary by individual customer. Customer vehicle type will impact the consumption significantly as well as impact the demand on the grid. A Tesla Model S charging rate is 10 kW, while a Chevy Volt charging demand is only 3.3 kW. The Nissan Leaf charging demand ranges from 3.3 kW to 6.6 kW depending on the options installed in the car. To put demand in perspective an average size residential home has approximately 33 kW in connected load of which, on average, 18 kW might be on during coincidental peak time. Typical residential demand breakdown by appliance is:

- Water Heater – 4.5 kW
- Range / Oven – 8.0 kW
- Central Air Conditioner – 6.0 kW
- Clothes Dryer – 5.0 kW
- Dishwasher – 2.0 kW
- Lighting, Fans, Appliances, Other – 7.5 kW

The most recent NIPSCO electric rate case indicated that the typical NIPSCO residential electric customer used 688 kWh per month on average during the weather normalized test year. The average EV consumption during the pilot is approximately 206 kWh; approximately 30 percent of the average home consumption. The type of vehicle purchased and the number of miles driven by the customer will directly impact the average consumption of the vehicle for each individual customer. NIPSCO found that the "free" energy during the off-peak times of 10 p.m. to 6 a.m. had a significant impact on charging behavior during the pilot. Figure 5-5 below is an hourly chart showing the typical usage by hour over the most recent three month period (October 2013 through January 2014). The vast majority of the time, EV residential customers begin their charging session at 10 p.m. when the energy discounted period begins and the vehicles will be fully charged by 6 a.m. when the energy discounted period ends. As predicted, the total energy consumption is higher during the work week, when owners typically drive their vehicles more than they do on weekends. The analysis provides indication that Time of Use ("TOU") rates do have an impact on pushing EV loads to more preferred off- peak times for utilities.

Figure 5-5
Response to Time of Use Pricing
Residential Home Charging
PY3 Q2 (Hour Ending Local Time)



NIPSCO IN-Charge Electric Vehicle Program – Around Town (Phase II)

NIPSCO, in partnership with South Shore Clean Cities, has expanded opportunities for alternative fuel, through the launch of a public charging station incentive program in February 2014. The NIPSCO IN-Charge Around Town Electric Vehicle Program aims to make it easier and more affordable for businesses and organizations to install public charging infrastructure.

IN-Charge Around Town incentive is to help with the up-front costs of public charging stations, in addition to installation costs and software subscriptions. The NIPSCO pilot program, available to commercial/industrial electric customers across northern Indiana, will continue through January 31, 2015, or until incentive funding subscription is full.

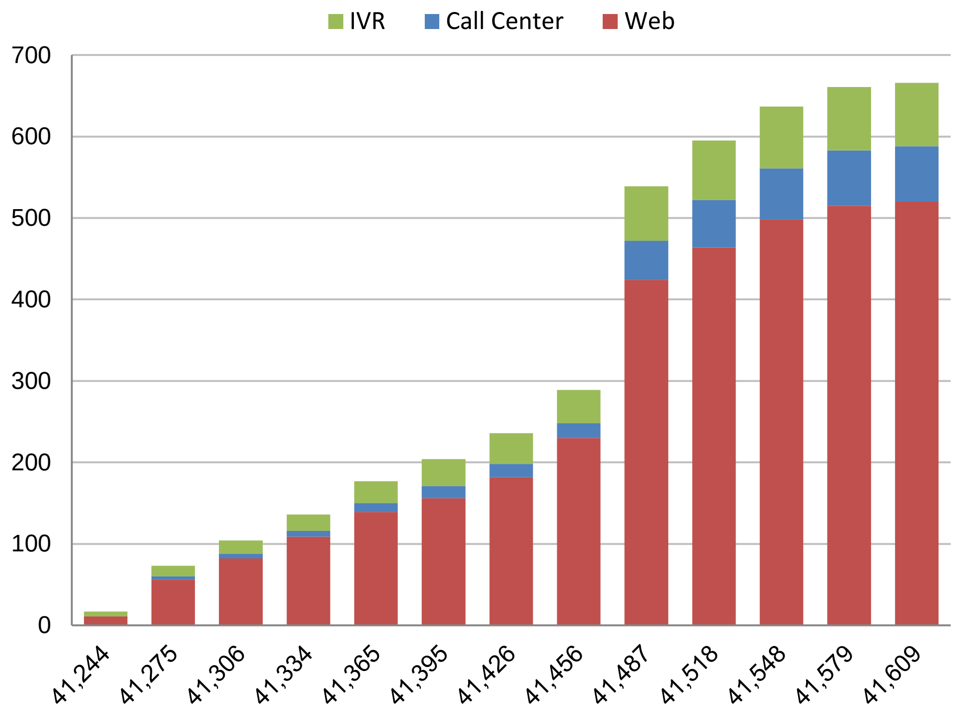
For every unit of electricity used by IN-Charge Around Town charging stations during the program, NIPSCO will buy an equivalent amount of renewable energy certificates ("RECs"). RECs are the environmental attributes associated with electricity that is generated from renewable sources, such as wind power.

As of July 31, 2014, NIPSCO has received 51 separate customer applications for public charging stations. Of the 51 customer applications, eight stations have been installed and another eight stations have been ordered, 13 additional quotes have been provided to customers for installation and are waiting on customer signed contract to proceed.

Green Power

On December 19, 2012, the Commission issued an Order in Cause No. 44198 approving NIPSCO's Green Power Rate ("GPR") Pilot Program. NIPSCO's GPR Program is a voluntary program that allows customers to designate a portion or all of their monthly electric usage to be attributable to power generated by renewable energy sources, such as wind power. Customers can enroll online, through the IVR or through a CSR. See Figure 5-6.

Figure 5-6
Cumulative Enrollment Type by Month



The GPR Pilot Program allows NIPSCO's electric customers to designate all or portions of their total electricity usage to be attributable to green power. Green power is energy generated from renewable and/or environmentally-friendly sources or a combination of both which meets the Green-e® Energy National Standard for Renewable Electricity Products in all regions of the United States. Eligible sources of Green Power include: solar; wind; geothermal; hydropower that is certified by the Low Impact Hydropower Institute; solid, liquid, and gaseous forms of biomass; and co-firing of biomass with non-renewables. Green Power includes the purchase of RECs from the sources described above. For the GPR Pilot Program, NIPSCO's residential electric customers can designate 25, 50 or 100 percent of their total electricity usage to be attributable to Green Power. In addition to those options, NIPSCO's commercial and industrial customers also have the option to designate five or ten percent of their total electricity usage to be attributable to Green Power. As of December 31, 2013, 606 customers were participating in the GPR Pilot Program.

Figure 5-7 below shows the breakdown among residential customers as of December 31, 2013. 78 percent of residential customers participating in the program designated 100 percent of their total electricity usage to be attributable to Green Power.

Figure 5-7
Residential Customer Count
by Dedicated Green Power Allocation as of 12/13/13

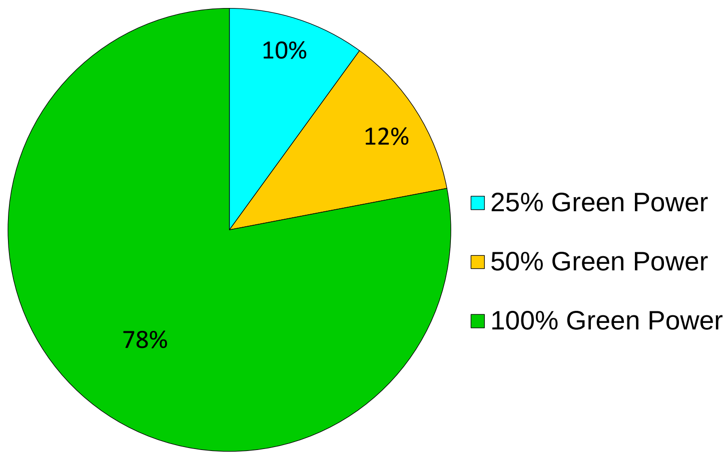
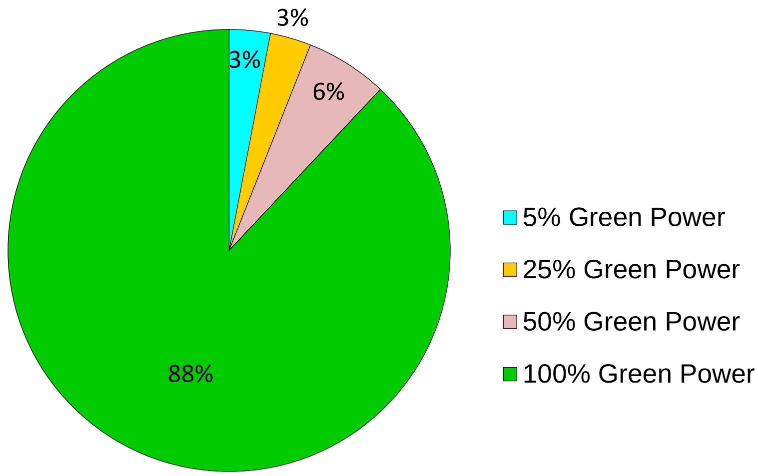


Figure 5-8 shows the breakdown of commercial and industrial customers as of December 31, 2013. There are 88 percent of commercial and industrial customers participating in the program that designate 100 percent of their total electricity usage to be attributable to Green Power.

Figure 5-8
Commercial Customer Count
by Dedicated Green Power Allocation as of 12/31/13



NIPSCO's GPR Pilot Program for the period January through December 2013 accounted for 5,215,678 kWh energy consumption of designated Green Power. Residential customers accounted for 1,884,472 kWh energy consumption of designated Green Power. Commercial and industrial customers accounted for 3,331,606 kWh energy consumption of designated Green Power. Although the majority of NIPSCO's customers enrolled in the GPR Pilot Program are residential customers, the bulk of the designated customer usage under the program is attributable to the small number of enrolled commercial and industrial customers. In addition, for both the residential and commercial customers, the majority of the enrollments and designated Green Power are those that designate 100 percent of their energy as Green Power.

Table 5-29 below shows the energy consumption of designated Green Power for all participants for the period January through December 2013.

Table 5-29
2013 All Customers (KWh)

All Rates	5%	25%	50%	100%	Total
Jan	503	169	717	7,348	8,736
Feb	438	782	2,654	33,223	37,096
Mar	473	1,743	2,830	55,450	60,496
Apr	406	1,890	3,627	60,191	66,113
May	361	1,521	5,354	452,184	459,420
Jun	419	2,148	7,088	486,553	496,207
Jul	570	3,311	9,481	540,437	553,798
Aug	436	3,356	10,446	511,748	525,986
Sep	458	13,196	20,520	790,419	824,593
Oct	344	10,776	18,327	633,808	663,254
Nov	367	11,350	19,442	640,876	672,035
Dec	451	15,334	24,693	807,465	847,944
Total	5,225	65,574	125,177	5,019,703	5,215,679
Total %	0.10%	1.30%	2.40%	96.20%	100.00%

Table 5-30 shows the energy consumption of designated Green Power for participating residential customer by rate for the period January through December 2013.

Table 5-30
2013 Residential Customers (KWh)

All Res Rates	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Total %
25%	169	782	1,743	1,890	1,521	2,148	3,311	3,356	13,196	10,776	11,350	13,273	63,513	3.4%
50%	717	2,654	2,830	3,627	5,354	7,088	9,432	10,386	20,463	18,266	19,375	24,609	124,798	6.6%
100%	7,348	28,106	48,126	54,338	69,060	93,787	131,455	158,959	281,762	223,671	239,142	360,008	1,695,763	90.0%
Total	8,233	31,542	52,699	59,854	75,935	103,023	144,197	172,700	315,421	252,713	269,867	397,890	1,884,074	100.0%
611														
25%	169	782	1,743	1,890	1,521	2,148	3,311	3,356	13,196	10,776	11,218	13,107	63,215	3.5%
50%	717	2,654	2,830	3,627	5,354	7,088	9,432	9,665	18,792	16,663	17,106	20,567	114,492	6.3%
100%	7,348	27,900	46,716	52,900	66,316	91,314	127,075	154,773	270,531	212,997	228,169	343,858	1,629,898	90.2%
Total	8,233	31,336	51,289	58,416	73,191	100,550	139,817	167,793	302,519	240,435	256,493	377,532	1,807,605	100.0%
612														
25%	-	-	-	-	-	-	-	-	-	-	132	166	298	0%
50%	-	-	-	-	-	-	-	721	1,671	1,604	2,269	4,043	10,307	15%
100%	-	-	1,185	959	2,233	1,561	3,190	3,190	9,822	9,657	10,039	14,963	56,800	84%
Total	-	-	1,185	959	2,233	1,561	3,190	3,911	11,493	11,261	12,439	19,171	67,405	100%
613														
25%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
50%	-	-	-	-	-	-	-	-	-	-	-	-	1	0.0%
100%	-	206	225	479	511	912	1,190	996	1,409	1,017	934	1,187	9,067	100.0%
Total	-	206	225	479	511	912	1,190	996	1,409	1,017	934	1,187	9,068	100.0%

Table 5-31 below shows the energy consumption of designated Green Power for participating commercial and industrial customers by rate for the period January through December 2013.

Table 5-31
2013 Commercial Customers (KWh)

All Com Rates	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	Total %
5%	503	438	473	406	361	419	570	436	458	344	367	451	5,225	0.1%
25%	-	-	-	-	-	-	-	-	-	-	-	2,062	2,062	0.0%
50%	-	-	-	-	-	-	49	61	57	61	68	84	380	0.0%
100%	-	5,117	7,324	5,853	383,124	392,766	408,982	352,789	508,657	410,137	401,734	447,457	3,323,941	63.7%
Total	503	5,555	7,797	6,259	383,485	393,185	409,601	353,286	509,172	410,542	402,168	450,054	3,331,608	63.9%
620														
5%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
25%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
50%	-	-	-	-	-	-	-	-	-	-	-	-	1	0.0%
100%	-	-	-	-	-	-	-	-	-	13,992	11,424	17,088	42,505	0.8%
Total	-	-	-	-	-	-	-	-	-	13,992	11,424	17,088	42,506	0.8%
621														
5%	503	438	473	406	361	419	570	436	458	344	367	451	5,225	0.1%
25%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
50%	-	-	-	-	-	-	8	17	7	8	7	21	67	0.0%
100%	-	5,117	7,324	5,853	17,046	20,286	23,662	23,297	29,528	27,119	26,342	31,804	217,379	4.2%
Total	503	5,555	7,797	6,259	17,407	20,705	24,240	23,750	29,993	27,470	26,715	32,276	222,671	4.3%
624														
5%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
25%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
50%	-	-	-	-	-	-	-	-	-	-	-	-	1	0.0%
100%	-	-	-	-	366,078	372,480	385,284	329,412	478,986	368,802	363,727	347,757	3,012,527	57.8%
Total	-	-	-	-	366,078	372,480	385,284	329,412	478,986	368,802	363,727	347,757	3,012,528	57.8%
660														
5%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
25%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
50%	-	-	-	-	-	-	41	44	51	54	61	63	314	0.0%
100%	-	-	-	-	-	-	36	80	143	224	241	346	1,071	0.0%
Total	-	-	-	-	-	-	77	124	194	278	302	409	1,385	0.0%
685														
5%	-	-	-	-	-	-	-	-	-	-	-	-	0	0.0%
25%	-	-	-	-	-	-	-	-	-	-	-	2,062	2,062	0.0%
50%	-	-	-	-	-	-	-	-	-	-	-	-	1	0.0%
100%	-	-	-	-	-	-	-	-	-	-	-	50,462	50,463	1.0%
Total	-	-	-	-	-	-	-	-	-	-	-	52,524	52,525	1.0%

Note (Tables 1, 2 and 3): The statistical information for January 2013 through December 2013 billing usage is derived from the number of customers and the Green Power energy billed each month during the period from NIPSCO's CIS billing system.

Participating customers are billed under their current applicable rate, with a separate line item showing the premium to participate in the GPR Pilot Program. This premium is calculated by multiplying the GPR rate by the kWh the customer specifies to be subject to the GPR. Table 5-32 shows the Green Power premiums applicable during the period January through July 2014.

Table 5-32
Green Power Premiums

	January 2013 through June 2013	July 2013 through December 2013	January 2014 through June 2014	July 2014 through December 2014
Green Power Factor	$ 0.002163	$ 0.002012	$ 0.002301	$ 0.001361
Percentage Change In Factor		-7.0%	14.4%	-40.9%

SECTION 6

Load and Resource Analysis

In This Section

- *Load and resources are balanced in the near-term.*
- *Potential resource portfolio adjustments are identified in 2023.*

Analysis of Resources

In Table 6-1 below is the assessment of NIPSCO's existing resources Unforced Capacity ("UCAP") against the future customers' needs from the NIPSCO's demand forecast (Internal Peak).

Table 6-1
Assessment of Existing Resources vs. Demand Forecast (BDSM)

Year	(a) Unforced Capacity - UCAP (MW)	(b) Internal Peak - FP0714c (MW)	(c) Demand Response (MW)	(d) Internal Peak Minus Demand Response (MW)	(e) Internal Peak Minus Demand Response Plus Reserve Margin (MW)	Capacity Position Long/(Short) (MW)
				(b)-(c)	(d) + (d) x Reserve Margin	(a)-(e)
2014	3,130	3,208	377	2,830	3,037	124
2015	3,143	3,212	377	2,835	3,042	101
2016	3,143	3,219	377	2,842	3,050	93
2017	3,143	3,235	377	2,858	3,066	77
2018	3,143	3,253	377	2,876	3,086	58
2019	3,143	3,273	377	2,896	3,108	36
2020	3,123	3,291	377	2,914	3,127	(4)
2021	3,123	3,311	377	2,934	3,148	(24)
2022	3,123	3,332	377	2,955	3,171	(47)
2023	2,973	3,352	377	2,975	3,192	(220)
2024	2,967	3,372	377	2,995	3,213	(247)
2025	2,967	3,391	377	3,014	3,234	(268)
2026	2,964	3,410	377	3,033	3,255	(290)
2027	2,964	3,429	377	3,052	3,275	(311)
2028	2,964	3,447	377	3,070	3,294	(330)
2029	2,657	3,465	377	3,088	3,314	(657)
2030	2,657	3,483	377	3,106	3,333	(676)
2031	2,654	3,497	377	3,120	3,347	(693)
2032	2,654	3,511	377	3,134	3,363	(709)
2033	2,654	3,542	377	3,165	3,396	(742)
2034	2,654	3,558	377	3,181	3,413	(759)
2035	2,208	3,574	377	3,197	3,430	(1,222)

NOTES:
1. UCAP is a NIPSCO estimated value
2. UCAP reflects units retiring after the peak season in the years - 2019, 2022, 2028 and 2034
3. Reserve Margin for 2014-2035 is 7.3%.

In Table 6-1, Column (e) is the result of Internal Peak minus Demand Response plus the MISO Planning Reserve Margin. Capacity Position is therefore calculated by subtracting Column (e) from Column (a).

Resource Alternatives (Section 7) discusses the resources options NIPSCO evaluated to bridge any capacity and energy gap. Resource Alternatives Analysis (Section 9) discusses how NIPSCO integrates those options with the existing resources. NIPSCO is committed to meet our customers' electrical needs with safe, reliable and affordable energy.

SECTION 7

Resource Alternatives

In This Section

NIPSCO evaluates a variety of resources to determine the optimal portfolio to serve customers' future needs.

- *Full suite of self-build supply-side, renewable, and DSM options assessed*
- *Detailed analysis of feasible gas and coal prototypes*
- *Sargent & Lundy engineering study provides closer assessment of resource costs and assumptions. AEG study provides assessment of DSM*

Resource Options Evaluated

NIPSCO's 2011 IRP identified no need for additional capacity and energy in the short-term. The same outcome holds true for the 2014 IRP.

In developing NIPSCO's 2014 IRP, traditional self-build supply-side options, renewable/distributed generation options, DSM energy efficiency, and DSM direct load control options were considered. Without a short-term requirement for new capacity and energy, a full evaluation of market options, i.e. a request for proposals ("RFP"), would be premature. The intent of NIPSCO's 2014 IRP is to address NIPSCO's current resource requirements through self-build, renewable, and DSM options. If the Short-Term Action Plan identifies a need for new capacity and energy, NIPSCO will evaluate market options in a separate RFP. One significant factor from the 2009 and 2011 IRPs continues to affect NIPSCO's 2014 IRP; the prolonged economic downturn has substantially lowered NIPSCO's forecast for demand and energy.

The analysis of self-build options considered a full range of traditional gas, coal, and nuclear prototypes. In addition, self-build options also considered a full range of renewable/distributed generation prototypes. NIPSCO commissioned an engineering study from the engineering firm Sargent & Lundy and a DSM study from AEG. The studies evaluated self-build, renewable/distributed generation, and DSM options for NIPSCO's long-range planning, and developed the costs and operating assumptions for various resources. The range of resources reviewed included the following:

Natural Gas

- Simple-Cycle Aeroderivative CT ("CTA") - Based on a review of small simple-cycle CT plants currently under construction or built in the U.S. since 2012, one of the most common aeroderivative engine choices has been the GE LM6000, which has a capacity around 50 MW. The LM6000 is attractive for peaking duty because of its operating efficiency. Aeroderivative engines are generally smaller, lighter, operate at higher speeds, and can require specialized maintenance personnel due to more technical, complex components. Aeroderivative engines can be designed to operate the compressor section at high revolutions per minute (rpm) for better efficiency while the generator operates at 3,600 rpm to match 60 hertz ("Hz") markets. The units can be used for system stabilization in case of upsets and rapid demand changes, taking advantage of their rapid start up and ramp up times. The LM6000PD-SPRINT model with the -

spray inter-cooled option for improved thermal efficiency and DLN combustors for emission control was selected as the reference technology for a small simple-cycle plant.

- Simple-Cycle Frame CT (“CTF”) - An industrial-frame or - heavy duty CT is generally designated as such because it is larger and heavier, operates at slower speeds, and is generally considered more rugged. The frame machines are also better suited for combined-cycle application due to their high exhaust temperatures and flows. The 220 MW Siemens SGT6-5000F(5)ee model was selected as the reference technology for a large simple-cycle plant. Since this machine has a long history of improved developments and is widely used throughout the power industry, it can reasonably represent an indicative cost and performance estimate for similarly sized projects. A single-unit configuration was assumed in this alternative option.

- Combined-Cycle (“CC”) - Typically, the CTs used for combined-cycle (CC) plants are industrial-frame units. The 220 MW Siemens SGT6-5000F(5)ee model was selected as the reference technology for similar reasons as stated for simple-cycle operation. A single plant configuration of 2 x 1, i.e., two CTs/heat recovery steam generators ("HRSGs") and one steam turbine ("ST"), was assumed in this alternative option as this is the most common arrangement.

- Bailly 7 Combined-Cycle Conversion (“CCB7”) - In the conversion of a coal plant to a combined-cycle gas plant, it is important to design and optimize the plant around the existing steam turbine and steam cycle of the coal plant. Due to the rating of the steam turbine at the Bailly Unit 7 (190 MW), conventional assumptions for a combined-cycle heat recovery steam generator in a 2 x 1 configuration would exceed the steam turbine generator capacity. Therefore, two F-class combustion turbines and two dual-pressure HRSGs were chosen to repower the steam turbine. This arrangement offers complete use of the steam turbine capacity at a reasonable efficiency.

- Schahfer Units 16A & 16B Combined-Cycle Conversion (“CCSH”) - Most combustion turbines can be expanded into a combined-cycle configuration with the addition of a steam cycle and only minor modifications to the CTs. For the combined-cycle conversion of Schahfer Units 16A and 16B, a condensing non-reheat dual-pressure-level steam cycle was chosen. This steam cycle effectively uses the energy from the exhaust gas and is typical for combustion turbines in this size range (70–100 MW).

- Combined-Cycle Conversion of Two-Unit Simple-Cycle Plant (“CONV”) - This alternative assumes a two-unit simple-cycle plant using Siemens SGT6-5000F(5)ee frame machines already exists. Therefore, the expansion into a combined-cycle configuration would require the addition of a steam cycle and only minor modifications to the CTs. For the combined-cycle conversion of this generic two unit simple-cycle plant, a condensing reheat three-pressure-level steam cycle was chosen. This steam cycle effectively uses the energy from the exhaust gas and is typical for combustion turbines in this size range (200+ MW).

Coal & Nuclear

- Supercritical Pulverized Coal (“PC”) - A plant design that uses ultra-supercritical steam conditions was chosen because it results in a more efficient steam cycle, leading to less coal per megawatt-hour and lower emissions. Carbon capture and sequestration (“CCS”) technology was assumed to meet anticipated CO_2 emissions requirements. CCS creates a significant parasitic load to the overall plant, which is dependent on the degree of CO_2 capture and the distance to storage. For this study, the amine process was used to develop an estimate for 40 to 50 percent capture. The CO_2 is assumed to be sequestered in a distant saline aquifer since none in northern Indiana are well suited environmentally. The land area for this option is sized for on-site disposal of coal by-products such as fly ash, bottom ash, and FGD waste; the power block, including the CCS equipment; a rail loop for the delivery of coal; and a landfill for disposal of bottom ash, fly ash, and FGD waste.

- Integrated Gasification Combined-Cycle ("IGCC") - The IGCC power plant conceptual design is based on two gasification and cleanup trains supplying synthesis gas (syngas) to power two F-class combustion turbine generators which in turn supply waste heat to two heat recovery steam generators and create steam for one steam turbine generator. Each gasification train converts coal (or petroleum coke, co-fired biomass, and other fossil combinations) into clean syngas with the help of an air separation unit. The syngas is processed to remove sulfur compounds, mercury, and particulate matter before it is used to fuel a CT. The integration of the plant is based on transferring steam, cooling water, and gases between the gasification island and the combined-cycle power block. The land area for this option was sized for the power block, including the CCS equipment; coal receiving, unloading, and handling equipment, which includes a rail loop for the delivery of coal; and landfill for disposal of slag/bottom ash. Sulfur acid is assumed to be sold in the market and requires no on-site storage except day-tanks to load the rail cars.

- Advanced Pressurized Water Reactor ("APWR") - The configuration considered is based on a Westinghouse dual-unit AP1000 design with a plant nameplate capacity of approximately 2,200 MW. Two APWR plants, Summer Units 2 & 3 and Vogtle Units 3 & 4, are under construction. These plants are AP1000 designs and, in the U.S., are the nearest new-build nuclear plants to commercial operation. Vogtle Units 3 & 4 are located in Georgia and are expected to be in operation in the fourth quarter 2017 and 2018, respectively. Summer Units 2 & 3 are located in South Carolina and are expected to be in operation in the first quarter 2018 and 2019.

- Small Modular Reactor ("SMR") - The SMR configuration is a smaller version of the advanced passive designs such as the AP1000, and ranges between 45 MW and 225 MW nameplate capacity. SMR designs have been undergoing extensive development for the last ten years and have recently been advanced in the commercialization process with funding from the United States Department of Energy's Small Modular Reactor program. There are now four main developers of the technology: Babcock & Wilcox, Westinghouse, NuScale, and Holtec. Each has a different design. None of the SMR designs has achieved commercial operation, but several developers have announced plant sites. In 2012, Department of Energy ("DOE") announced that Babcock & Wilcox was selected for first-round funding for its mPower design. The remaining three developers have all submitted applications for second-round funding. The earliest commercial operation of any the developers is currently expected to be 2022.

Renewable/Distributed Generation

- Biomass – Stoker Boiler ("BIOS") - The likely candidates within northern Indiana for biomass energy come in two forms: agricultural crop residues for utility-scale application and biogases for distributed generation applications. The available energy capacity due to crop residues compatible with stoker boilers is estimated to be only approximately 20–40 MW within northern Indiana. There is some interest in pelletizing corn stover within the Midwestern regions where corn is the dominant crop. If the supply chain is developed, then the available energy capacity could increase since agricultural crop residue is fairly high in the territory. As a result, biomass energy where corn stover is burned in a stoker boiler was considered in the evaluation of the cost and performance of viable alternatives on the utility scale. Stoker boiler technology employs direct-fire combustion of solid fuels to produce steam. The steam is used directly for heating or is passed through a steam turbine generator to produce electric power. Stoker boiler technology is well-known and operational throughout the U.S. and is typically applied to utility-scale generation.

- Biomass Reciprocating Engine ("BIOR") - Within northern Indiana, the total available energy capacity due to methane from manure management, methane from wastewater treatment facilities, and landfill gases is estimated to total approximately 25 MW. These gases are generally fired in reciprocating engines, which operate by passing recovered natural gas, methane, or other fossil fuel through a modified internal combustion engine, which turns a generator that produces electricity. Since these biogases can be collected on-site at commercial facilities, this form of biomass energy is well-suited for distributed generation. Therefore, reciprocating engines firing biogases were considered in the evaluation of the cost and performance of viable alternatives as a distributed generation project within this report.

- Concentrated Solar Power ("CPV") - This technologies use mirrors to concentrate sunlight onto a central point in order to heat up a working medium, which ultimately produces electricity in a steam cycle. CPV plants are designed to be large-scale grid-connected plants, but at present they generally cannot be used as baseload generators because of low capacity factors. Solar thermal plants without energy storage capabilities do not produce heat at night or during the times when clouds block the sun. The annual capacity factor of any CPV technology falls in a range of 20 to 28 percent. Some systems use thermal energy storage, setting aside heat transfer fluid in its hot phase during cloudy periods or at night. However, even if a thermal storage technique is used with a CPV system, the capacity factor has the potential to increase to only 40 to 50 percent. Consequently, even with thermal storage, solar thermal capacity factors are more typical of peaking or mid-merit intermediate resources as opposed to baseload resources.

- Solar Photovoltaic ("PV") – Solar photovoltaic technologies convert sunlight directly into electricity through solar panels that can be arranged in arrays to increase electricity output. Even though large utility-scale PV facilities remain comparatively more expensive than other bulk-power options, there has been a growing trend in some markets toward new PV projects being developed in the 10 MW and larger capacity range. Similarly, deployment of relatively small-scale distributed generation in residential- and commercial-scale applications has also continued to grow. Innovations in PV technologies and policies that encourage investment through rebates, subsidies, feed-in tariffs, and tax incentives are making small-scale on-site generation increasingly attractive and economically competitive.

- Onshore Wind ("WNON") - The use of wind power for electrical generation is based on proven and commercially available technology that is currently used in the state of Indiana. The state of Indiana currently ranks 13th in the U.S. of total installed capacity with 1,543 MW generated from 929 wind turbines. The total operating wind farm capacity in northern Indiana is approximately 1,340 MW, which comprises approximately 87 percent of the state's developed wind capacity.

- Offshore Wind ("WNOF") - Offshore wind turbines have been placed into commercial operation in many countries throughout the world; however, not a single offshore turbine is in operation within the United States. Wind speeds offshore are typically higher and steadier than wind speeds onshore, suggesting higher potential electricity generation and thus increased attractiveness. However, the cost associated with construction and maintenance for offshore projects is also higher. The northwest corner of Indiana is contiguous with the shore of Lake Michigan where wind resource is better than onshore. Directly off the shore of Indiana, at a height of 90 meters, the average annual wind speed is 6.5 m/s; whereas three miles offshore, the average annual wind speed reaches as high as 8.5 m/s.

- Geothermal ("GEO") - The electric power generation potential of conventional geothermal resources in the United States is limited to Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming, which contain all 241 identified moderate- and high-temperature geothermal systems located on private or accessible public lands. Since Indiana is not located within or near a favorable geothermal location, power production due to geothermal resources is not evaluated further.

- Energy Storage - Pumped Storage ("PSH") - Pumped hydroelectric energy storage is a mature technology with large generation capabilities when compared with other storage devices and is both proven and commercially available. Pumped storage projects can be practically sized up to 4,000 MW and operate at about 76 to 85 percent efficiency. Pumped storage has disadvantages in that facilities are upfront capital intensive, take up large spaces, and have extensive permitting procedures. The prime locations for pumped storage typically exist in mountainous regions with large grade differentials. The state of Indiana is relatively flat in comparison to the areas with proposed hydro storage facilities. Constructing a hydro storage facility in a relatively flat area requires additional earthwork, which increases the upfront capital cost and, therefore, decreases the economic attractiveness. Given the unfavorable topography in northern Indiana and the surrounding area, it was determined that a pumped storage project is not practical, and therefore, it is not evaluated further.

- Energy Storage - Compressed Air ("CAES") - Compressed air energy storage systems use off-peak electricity to compress air and store it in a reservoir, either an underground cavern or aboveground pipes or vessels. When the demand for electric power peaks, the process is reversed and fed into industrial gas turbines. Underground storage yields larger capacity, up to 400 MW; higher discharge times of eight to 26 hours, and lower cost than above-ground storage, but it requires geologic conditions that are conducive to storage. The commercially operational plants currently use salt mines for storage. While it does not have salt mines, Indiana does have coal mining activity in the southwestern part of the state. However, coal mines are typically in sedimentary rock, which could bleed and be unable to maintain pressures.

- Energy Storage - Liquefied Air (“LAES”) - Liquefied air energy storage systems use off-peak electricity to liquefy air and store it in insulated tanks. When the demand for electric power peaks, the process is reversed. The liquefied air is expanded nearly 700 times its volume and is fed into an industrial gas turbine, allowing the turbine to produce electricity more efficiently.

- Energy Storage – Batteries (Commercially Available) (“BATC”) - With regards to commercially available options, advanced lead-acid and sodium sulfur batteries have been implemented in large-scale applications such as bulk utility distribution grid support, renewable integration, and high-value grid services. These batteries have the potential for use in grid services because of their long discharge period and their ability for prompt, precise response to grid needs such as mitigation of power quality events and regulation of voltage. On the distributed generation scale, advanced lead-acid and sodium sulfur batteries have served in a few applications such as transmission and distribution (“T&D”) substation support and commercial energy management.

- Energy Storage – Batteries (Emerging Technology) (“BATE”) - The variation in services and characteristics has led to the application of various battery types and configurations within the power industry. Some battery types such as lead-acid and sodium sulfur are proven and commercially available, whereas others such as zinc-bromine, zinc-air, and lithium ion are in the research and development or demonstration phase. None, however, has emerged as the dominant technology choice across the board. For this report, only battery types that are commercially available were evaluated on a cost and performance basis.

- Microturbines (“MT”) - Microturbines are very small gas turbines, 30 kW to 400 kW, attached to high-speed electrical generators. They can be powered by natural gas or biofuels and can be configured to provide both electricity and heat. Microturbines are well-suited for a variety of distributed generation applications due to their size range, flexibility in connection methods, ability to be stacked in parallel to serve larger loads, ability to provide reliable power, and low-emissions profile. Target applications include peaking power, premium power, remote power, and grid support services. Due to the range of applications and the inherent benefits in each, microturbines are considered in the evaluation of the cost and performance of viable alternatives within the distributed generation scale only.

- Fuel Cells (“FC”) - The fuel cell is an energy conversion device that can efficiently capture and use the power of hydrogen by directly converting the chemical energy in hydrogen to electricity, with pure water and potentially useful heat as the only byproducts. Stationary fuel cell systems can be used for backup power, power for remote locations, stand-alone power plants for towns and cities, distributed generation, and co-generation in which excess thermal energy from the chemical process is used in direct heating, cooling applications, or electricity production. Typically, the most economic means of using the heat is to provide direct heating, but in absence of significant heat demand, the other applications may be economical.

Demand Side Management & Energy Efficiency

- Commercial HVAC ("CHVC") - The Commercial and Industrial HVAC program provides businesses with weatherization techniques and assistance designed to promote energy efficiency measures.

- Commercial Lighting ("CLIG") - The Commercial Lighting Program implements a multitude of direct install measures, which include the use of CFL lamps, lighting occupancy sensors and LED exit signs, to promote and ensure light saving in schools and businesses, both small and moderately-sized.

- Commercial Process ("CPRO") - The Commercial Process Program implements a multitude of direct install measures to promote and ensure commercial and industrial process automation savings, both small and moderately-sized.

- Commercial Other ("COTH") - Miscellaneous energy efficiency procedures for small- and moderately-sized commercial and industrial businesses constitute a program called the Commercial Other Program.

- Residential HVAC ("RHVC") - The Residential HVAC program employs educative and assessment-based weatherization techniques in an effort to propel energy savings in various types of households, from low-income to single-family, etc.

- Residential Lighting ("RLIG") - The Residential Lighting Program will provide incentives and marketing support through retailers to build market share and usage of ES and other energy efficient lighting products. The program targets the purchase of lighting products through in-store promotion as well as special sales events. Customer incentives facilitate the increased purchase of high-efficiency products while in-store signage, sales associate training and support makes provider participation easier.

- Residential Other ("ROTH") - Miscellaneous energy efficiency procedures for residential homes constitute a program called the Residential Other Program.

Demand-Side Management/Direct Load Control

- Residential AC Cycling ("RACC")
- Industrial Direct Load Control ("IDLC")

NIPSCO's Resource Technology Assessment

All of NIPSCO's self-build supply-side resources are commercially proven technologies. NIPSCO has no desire to enter the field of nuclear generation. However, for the purposes of this 2014 IRP, NIPSCO evaluated the economic impacts of nuclear generation within the resource optimization. The remaining renewable/distributed generation resource options are summarized in Table 7-1.

Table 7-1
Renewable and Storage Technology Summary

Technology	Utility Scale	Intermediate DG	FIT Program DG
Biomass – Stoker Boiler	Yes		
Biomass – Reciprocating Engine		Yes	Yes
Concentrated Solar Power	No		
Solar Photovoltaic	Yes	Yes	Yes
Wind – Onshore	Yes	Yes	Yes
Wind – Offshore	No		
Geothermal	No		
Energy Storage – Pumped Storage	No		
Energy Storage – Compressed Air	No		
Energy Storage – Liquefied Air	No		
Batteries – Commercial	Yes	Yes	
Batteries – Emerging	No	No	
Microturbines		Yes	
Fuel Cells	No	No	

Based upon this technical assessment, NIPSCO will move forward with the following renewable/distributed generation technologies: Biomass – Stoker Boiler, Biomass – Reciprocating Engine, Solar Photovoltaic, Wind – Onshore, Batteries – Commercial, and Microturbines.

NIPSCO DSM energy efficiency options were evaluated according to industry standard approaches: UCT, TRC Test, RIM Test, Societal Test, and Participant Test. All of NIPSCO's DSM energy efficiency options passed and were considered in the resource optimization. In addition, RACC cycling and IDLC are commercially available technology and were considered in the resource optimization.

NIPSCO's Self-Build Traditional Resource Analysis

NIPSCO based the cost of self-build supply-side resources on estimates provided by Sargent and Lundy in December of 2013. NIPSCO focused its self-build supply-side resource opportunities for inclusion in the 2014 IRP on widely available, commercially and technologically mature options in order to reduce the opportunity for cost escalation or failure. Resource options are summarized in CONFIDENTIAL Appendix I.

The NIPSCO self-build supply-side resource options were initially evaluated using a levelized cost screening to determine which options would be preferred for the peaking, intermediate, and base load operating cycles, for example, capacity factor. The results for this screening for supply-side resources are expressed in levelized $/kW-year for various capacity factor levels and are shown in Figure 7-1. These values include all capital construction and associated costs as well as fixed and variable O&M costs, and fuel costs. The capital costs include overnight construction costs, property taxes and insurance, and transmission interconnection costs. Capital construction costs escalate at an annual rate of three percent, a before tax weighted cost of capital of 8.56 percent, an AFUDC rate of 7.56 percent, and a discount rate of 7.68 percent. Transmission system upgrade costs associated with these generic resources are not included since the estimates were not site specific. Variable costs include variable O&M costs, fuel costs, and all associated emissions costs (SO_2, NO_x and CO_2). Long run fuel prices escalations are 2.91 percent for PRB coal, 2.44 percent for Illinois Basin coal, and 4.35 percent for natural gas. Variable and fixed O&M costs are assumed to escalate at 1.71 percent over the long term.

The horizontal axis is capacity factor. The horizontal axis is the independent variable that defines how much the unit operates from 0 to 100 percent. The vertical axis is the levelized cost, in $/kW-Year. The levelized cost represents the present value of the total cost of building and operating a generating plant over its book life, converted to equal annual payments and amortized over the expected annual generation from an assumed duty cycle, or capacity factor. Figure 7-2 generalizes the levelization process.

Figure 7-1
Utility Self-Build Screening Curves

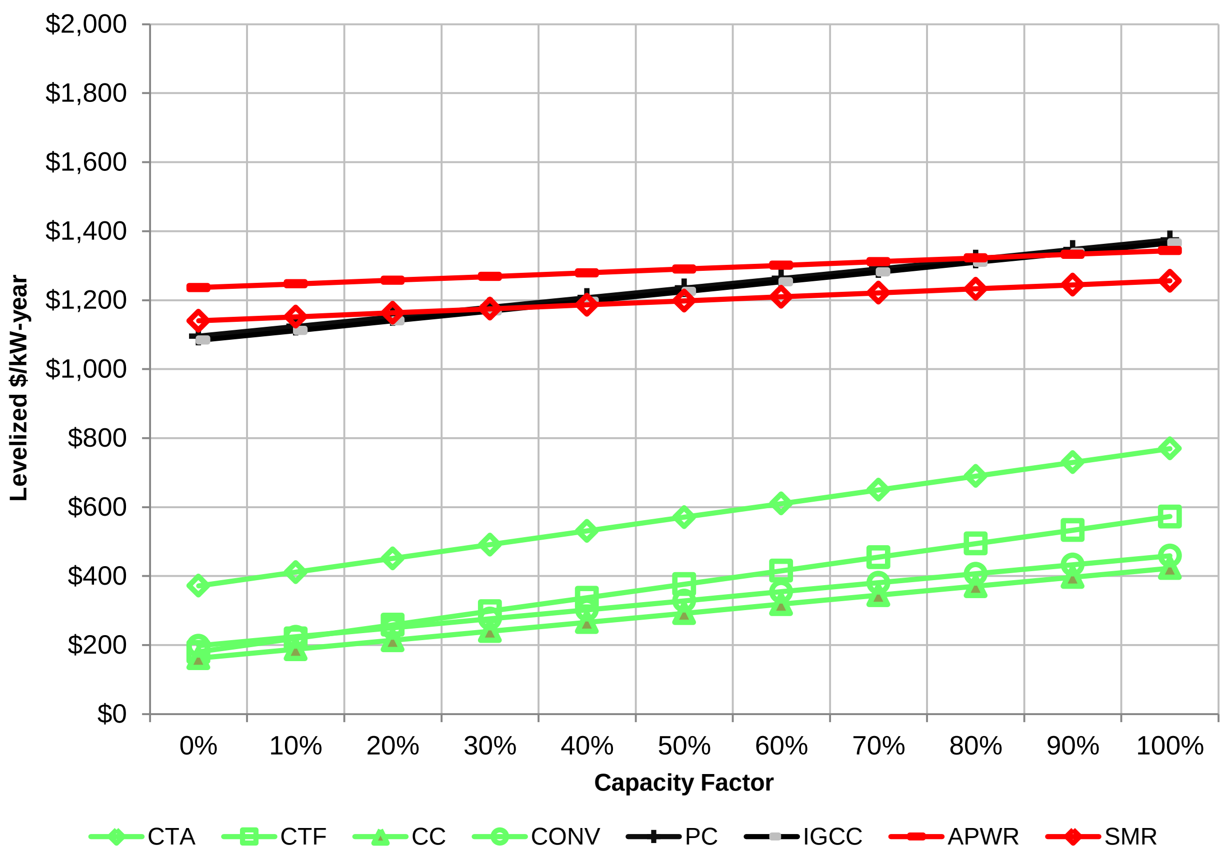
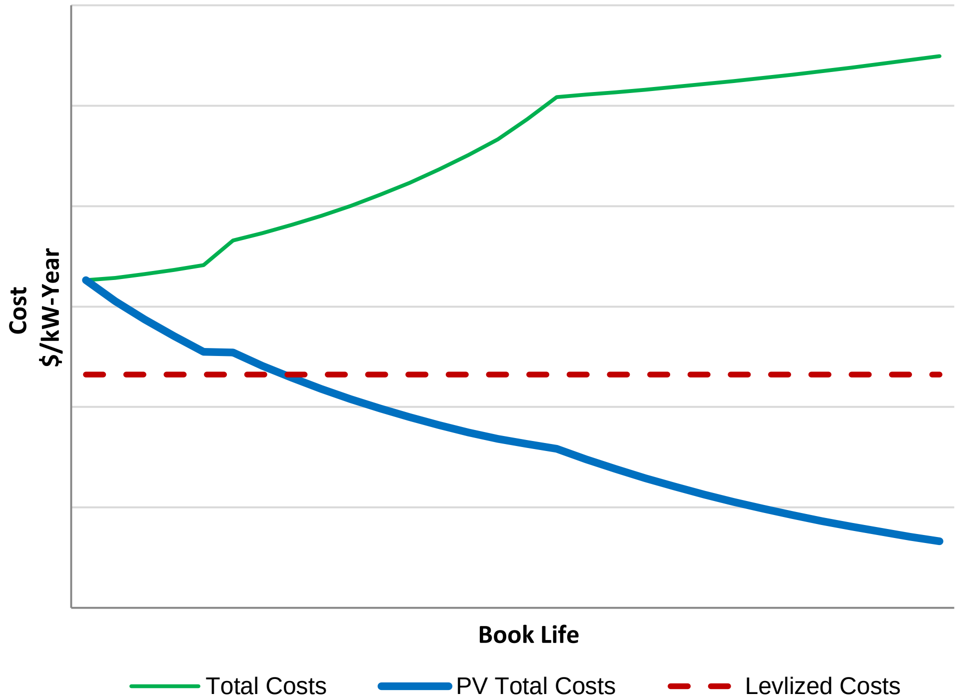


Figure 7-2
Levelized Cost Example



The CCGT and associated conversion CCGT's are economic across all capacity factors. Based on these results, the expected optimal plan will contain some combination of CCGT technologies. The remaining technologies will be included in the sub-optimal plans. All of the self-build supply-side options were carried forward into the supply-side and demand-side Integration phase of the IRP as potential self-build supply-side alternatives.

Construction lead times are an important consideration. The construction lead times and the first year that a resource could be added are shown in Table 7-2.

Table 7-2
Utility Self-Build Construction Lead Times

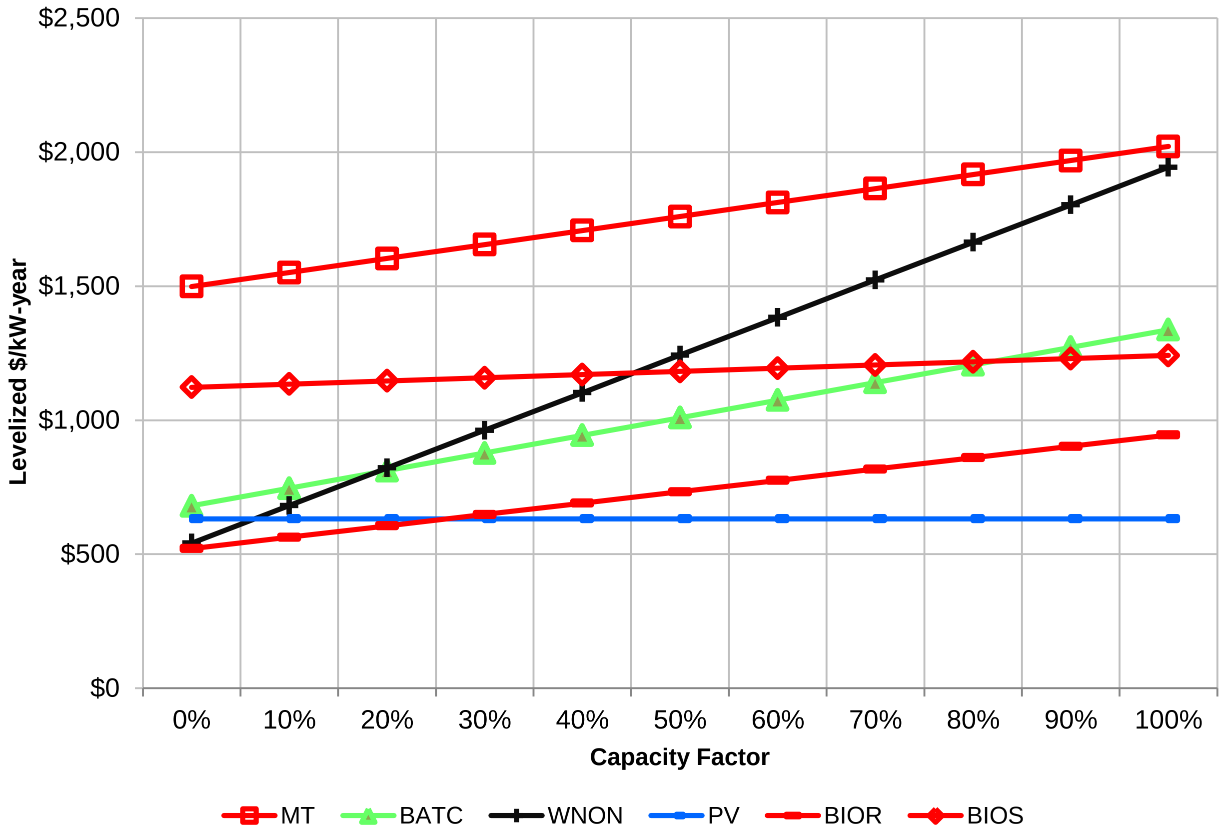
	CTA	CTF	CC	CONV	PC	IGCC	APWR	SMR
Construction Lead Time (Years)	3	3	4	4	5	6	11	8
First Year Available	2016	2016	2017	2017	2018	2019	2024	2021

NIPSCO's Self-Build Renewable Resource Analysis

NIPSCO based the cost of self-build supply-side resources on estimates provided by Sargent and Lundy. The self-build renewable resources are summarized in CONFIDENTIAL Appendix I. The NIPSCO self-build renewable options were initially evaluated using a levelized cost screening to determine which options would be preferred for the peaking, intermediate, and base load operating cycles, i.e., capacity factor. The results of this screening are expressed in levelized $/kW-year (2013$) for various capacity factor levels and are shown in Figure 7-3. These values include all capital construction and associated costs as well as fixed and variable O&M costs, and fuel costs. These values include all capital construction and associated costs as well as fixed and variable O&M costs, and fuel costs. Capital construction costs escalate at an annual rate of three percent, a before tax weighted cost of capital of 8.56 percent, an Allowance for Funds Used During Construction ("AFUDC") rate of 7.56 percent, and a discount rate of 7.68 percent. Transmission system upgrade costs associated with these generic resources are not included since the estimates were not site specific.

The wind and solar renewable options have no variable operating expenses. The biomass renewable option does include a variable O&M expense escalating at 1.71 percent over the long term. The biomass renewable option uses regenerative organic material for energy production. Biomass fuel typically consists of forestry materials, wood residues, agricultural residues, and energy crops. NIPSCO used a price of $7/MBTU (2013$) to price the expected quantities of agricultural commodity crops available for biomass. Biomass fuel costs escalate at 2.44 percent over the long term. The feasible operating range for biomass is from a 0 to 100 percent capacity factor, solar is from a 0 to 30 percent capacity factor, and wind and battery are from 0 percent to 50 percent capacity factor.

Figure 7-3
Utility Self-Build Renewable Screening Curves



Construction lead time is an important consideration. The construction lead time and the first year that a resource could be added are shown in Table 7-3.

Table 7-3
Utility Self-Build Renewable Construction Lead Times

	BIOS	BIOR	PV	WNON	BATC	MT
Construction Lead Time (Years)	4	1	3	4	1	1
First Year Available	2017	2014	2016	2017	2014	2014

Market-Based Options

NIPSCO did not undertake a comprehensive review of market options NIPSCO intends to use the results of the 2014 IRP as the basis for a future RFP to fully evaluate the market options available, when a short-term need for capacity and energy is required.

Expansion Planning Criteria

The 2014 IRP involved a comprehensive assessment of the generation expansion planning criteria to determine what level of capacity is necessary to serve customers safely, reliably and adequately at the lowest reasonable cost. These criteria, among others, assisted in screening the pool of available resource options.

Planning Reserve Margin - A minimum Planning Reserve Margin will ensure a minimum level of resource adequacy. The MISO UCAP planning protocol was used. To ensure that the correct criteria was employed, the Company constrained the 2014 IRP optimization so that no resource mix would be accepted that achieved a Planning Reserve Margin of less than 7.30 percent for years 2014 to 2035. Based upon NIPSCO's generation fleet reliability, MISO's targeted UCAP planning reserve margin of 7.30 percent is roughly equivalent to a traditional Planning Reserve Margin of 9 to 12 percent using the Installed Capacity ("ICAP") planning protocol.

An adequate minimum Planning Reserve Margin will minimize loss of load hours and the system's reliance on emergency energy. Maximum Planning Reserve Margin constraints for the optimizations were set between 50 and 70 percent, annually across the study horizon. These constraints are non-binding. This maximum Planning Reserve Margin constraint is high enough to allow the addition of large resources, but not so high as to permit overbuilding.

Economically Ranking Competing Plans - A minimization of Net Present Value Revenue Requirements ("NPVRR") criterion was used in the Strategist model for economically ranking competing plans from the optimization. NIPSCO modeled 100 percent of off-system margins returned to NIPSCO customers. In addition, NIPSCO tested the impact of a 50/50 split of off-system margins to NIPSCO customers and shareholders and determined that the treatment of off-system margins had no impact on the resource decisions.

Siting Issues and Related Constraints – NIPSCO evaluated both a brownfield development and a greenfield development. The existing Sugar Creek facility has sufficient infrastructure to accommodate two additional brownfield CTs or one additional brownfield CCGT.

The planning criteria also involved a technology assessment of supply-side generating resources. The technology assessment evaluated whether the supply-side resource had certain technology adaptive characteristics. For instance, NIPSCO sought to ensure that the selected resource technology is commercially available in order to maximize reliability and price certainty. Commercially mature technologies were preferred (see Table 7-4). NIPSCO preferred resources that promoted fuel diversification and fuel transportation diversity to engage a diverse and balanced range of fuels while maintaining economic flexibility and avoiding undue reliance. NIPSCO also considered operational flexibility, such as those that offer Automatic Generation Control ("AGC") and black start capability, along with the greatest degree of scheduling flexibility. See CONFIDENTIAL Appendix K.

Table 7-4
Generation Technology Database

Description	Simple Cycle GT	CCGT	Supercritical PC	IGCC[1]
Source	Vendor	Vendor	Vendor	Vendor
Technology Development Rating	Mature	Mature	Mature	Mature
Cost Estimate Rating	Engineering	Engineering	Engineering	Engineering
Significant Solid Waste Disposal	None	None	Potential	Potential
Significant Hazardous Waste and Disposal	Negligible	Minimal	Minimal	Minimal
Fuel Type	Natural Gas	Natural Gas	Coal	Coal

[1] The IGCC Unit is assumed to be a 1x1x1 configuration

In addition, the 2014 IRP planning criteria incorporated several financial goals to promote a thorough resource evaluation and selection process. Topmost among these were cost effectiveness, which would be achieved by securing a portfolio of reasonable least cost assets. The plan minimizes the Net Present Value ("NPV") of NIPSCO's generation-related revenue requirement over the time period of 2014 through 2035. Resources that would provide rate stabilization and minimize the impact of large capital additions on customer rates are provided. The 2014 IRP goals focus on the ability to balance interests between the NIPSCO's interest in securing reliable generating facilities that contribute to its opportunity to earn its allowed return and its customers' interests in lowest reasonable cost electricity service. Price certainty is promoted by securing a robust portfolio of self-build supply-side options, renewable options and demand-side management. Finally, the 2014 IRP minimizes volatility by looking for opportunities to reduce fuel and energy market volatility.

The 2014 IRP also defines a resource attributes list used for screening the supply-side options. The first attribute is reliability. Under this standard, each resource in the plan must reflect a minimum amount of secured capacity to meet projected summer peak demands, associated energy needs, and the provision of adequate planning reserves per year over the time period of 2014 through 2035. The second attribute is ancillary services that would permit NIPSCO to maximize reliability and minimize cost by securing resources that would be capable of contributing to the overall reliability of the NIPSCO system. As further defined, resources which reflected maximum flexibility and provision of the following ancillary services:
1) reactive power; 2) contingency reserves/quick start capability; 3) spinning reserves; and 4) black start capability met the identified reliability attribute. The third measurement criterion is the evaluation of congestion and marginal losses to minimize the impact of congestion and marginal losses between the resource's location/delivery point and the NIPSCO load zone.

SECTION 8

Environmental Considerations

In This Section

- *NIPSCO is committed to ongoing environmental compliance.*
- *NIPSCO's Multi-Pollutant Compliance Plan is based on EPA Consent Decree, the EPA Clean Air Interstate Rule and Cross State Air Pollution Rule ("CSAPR") and Utility Mercury and Air Toxic Standard ("MATS") with a 2012 – 2022 compliance timeline.*
- *Compliance requires substantial investments in NIPSCO's generation fleet.*

Environmental Compliance Issues

NIPSCO is committed to complying with all environmental, legal, and other regulatory requirements affecting the environment. This commitment is embodied in the NIPSCO Environmental Policy and is implemented through an environmental management system. NIPSCO operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. Compliance plan options are developed, reviewed and evaluated for implementation to meet new legislative and regulatory developments. In the following paragraphs, NIPSCO discusses each of the complex environmental issues.

Environmental Issues Affecting NIPSCO Generation

- Greenhouse Gases
- Mercury and Air Toxics Standard
- Cooling Water Intake Structures
- Effluent Guidelines
- Coal Combustion Residuals

Clean Air Act

NIPSCO expects a number of new air-quality mandates to be phased-in over the next several years. These mandates will require NIPSCO to make capital improvements to its electric generating stations.

Greenhouse Gases **-** Existing climate-related environmental laws and regulations may be revised and new laws and regulations may be adopted or become applicable to NIPSCO. Revised or additional laws and regulations could result in significant additional operating expense and restrictions on NIPSCO's facilities and increased compliance costs. Moreover, such costs could affect the continued economic viability of one or more of NIPSCO's facilities.

Because NIPSCO operations involve the use of natural gas and coal fossil fuels, emissions of GHG are inherent in the business. While NIPSCO has reduced GHG emissions through efficiency and other programs, GHG emissions cannot be entirely eliminated. On June 25, 2013, the Executive Office of the President of the United States issued a Climate Action Plan. One of the three pillar components of the plan is to cut GHG emissions and most specifically to cut GHG emissions from power plants. In addition to the plan, the President issued a memorandum directing the EPA to finalize GHG standards for both new and existing generating units. The EPA is using the Clean Air Act to issue New Source Performance

Standards ("NSPS") to reduce GHG emissions from electric generating units ("EGUs"). On June 2, 2014, the EPA proposed a GHG performance standard for existing fossil fuel-fired electric generating units under section 111(d) of the CAA. The proposed rule establishes state-specific CO_2 emission rate goals and requires each state to submit a plan indicating how the generating units within the state will meet the EPA's emission rate goal. Final CO_2 emission rate standards are expected to be set by the EPA in June 2015, and state plans are required to be submitted to the EPA as early as June 2016. The cost to comply with this rule will depend on a number of factors, including the requirements of the final federal regulation and the level of NIPSCO's required GHG reductions. It is possible that this new rule, comprehensive federal or state GHG legislation, or other GHG regulation could increase NIPSCO's cost of producing energy, which could impact customer demand and customer costs.

At this time it does not appear likely that widespread GHG reductions will be required until, at a minimum, the latter half of this decade. NIPSCO is estimating that a price on carbon will not be established prior to 2025 due to the current economic and political environment, in addition to the time required for a widespread program to be developed and implemented.

National Ambient Air Quality Standards ("NAAQS") - The CAA requires the EPA to set national air quality standards for particulate matter ("PM") and five other pollutants considered harmful to public health and the environment. The EPA imposes new, or modifies existing, NAAQS periodically and requires states that contain areas that do not meet the new or revised standards to take action toward achieving compliance with the standards through the use of local- or regional-based emission control measures. These actions could include adding pollution controls on facilities owned by electric generation.

The following NAAQS were recently added, modified, or are in the process of being revised:

- Ozone NAAQS - EPA designated Lake and Porter (Bailly Generating Station) Counties as nonattainment effective July 20, 2012. Jasper County (Schahfer Generating Station) remains in attainment. Since the Bailly Station has installed SCR, the nonattainment designation is not likely to change any NIPSCO generation station emissions control requirements.

- SO_2 NAAQS - On December 8, 2009, the EPA revised the SO_2 NAAQS by adopting a new 1-hour primary NAAQS for SO_2. The EPA designated areas that do not meet the new standard. Counties in which NIPSCO has coal-fired generating stations are currently designated as unclassifiable. NIPSCO's Compliance Plan includes installation of three new scrubbers, resulting in all of its coal units being controlled for SO2. Therefore, NIPSCO does not expect that future attainment designations will likely change any NIPSCO generation station emissions control requirements.

- PM NAAQS - On January 15, 2013, EPA published an update to the annual health standard at 12 micrograms per cubic meter. All counties in which NIPSCO has coal-fired generating stations are currently designated as either attainment or unclassifiable with the PM NAAQS.

Acid Rain Program - NIPSCO is fully in compliance with the EPA's Acid Rain Program. The CAA Amendments of 1990 introduced a new nationwide approach to reduce the emission of acidic air pollutants. The Acid Rain Program was designed to reduce electric utility emissions of SO_2 and NO_x

through a market-based cap and trade system. While the SO_2 reductions were achieved in two phases by the establishment of lower overall emissions caps, NO_x emission controls were required using a two-phased control technology-based emission reduction program.

Regional Pollutant Transport Requirements - The EPA has determined that, for purposes of achieving ozone and particulate attainment, emissions from certain upwind states, including Indiana, 'contribute significantly' to downwind state nonattainment areas. As a result, the NO_x State Implementation Plan ("SIP") Call (Call being the EPA requirement, or call, for individual states to develop SIPs to reduce NO_x emissions) and CAIR regional emission control programs were developed to address regional pollutant transport issues and are more fully described below. Emission reductions from NIPSCO generating stations have been identified to address both local nonattainment as well as regional pollutant transport issues.

- CAIR - CAIR remains in effect after the CSAPR was vacated on August 21, 2012. Both CSAPR and CAIR are emission allowance trading programs that established NO_x and SO_2 emission allowance allocations for each NIPSCO generating unit. NIPSCO has considered the long-term compliance implications of NO_x and SO_2 allowance trading programs of similar stringency to CAIR or CSAPR in its planning process.

- CSAPR / CAIR / Transport Rule - On July 6, 2011, the EPA announced its replacement for the 2005 CAIR to reduce the interstate transport of fine particulate matter and ozone. The CSAPR reduces overall emissions of SO_2 and NO_x by setting state-wide caps on power plant emissions. The EPA initially intended to implement an emissions trading program and other aspects of the CSAPR in 2012, but this implementation date was delayed by litigation. The EPA has received permission from the court to begin enforcing CSAPR on January 1, 2015. The EPA's implementation of CSAPR would not significantly impact NIPSCO's current emissions control plans. NIPSCO believes its current multi-pollutant compliance plan and New Source Review Consent Decree capital investments will allow NIPSCO to meet the emission requirements of CAIR as well as CSAPR if reinstated.

Utility MATS Rule - On December 16, 2011, the EPA finalized the MATS rule establishing new emissions limits for mercury and other air toxics. Compliance for NIPSCO's affected units is required by April 2015 and April 2016. NIPSCO developed and obtained IURC and Indiana Department of Environmental Management ("IDEM") approval of a plan for environmental controls to comply with MATS. Table 8-8 includes new air emission controls needed to comply with MATS.

Consent Decree

On September 29, 2004, the EPA issued a Notice of Violation ("NOV") to NIPSCO for alleged violations of the CAA and the SIP. The NOV alleges that modifications were made to certain boiler units at three of NIPSCO's generating stations between the years 1985 and 1995 without obtaining appropriate air permits for the modifications. NIPSCO, the EPA, the Department of Justice, and the IDEM have agreed to settle the matter.

The Consent Decree was entered by the United States District Court for the Northern District of Indiana on July 22, 2011. The Consent Decree covers NIPSCO's four coal generating stations: Bailly, Michigan

City, Schahfer, and Mitchell. NIPSCO surrendered CAA permits for Mitchell's coal-fired boilers, which have not been used to generate power since 2002. At the other generating stations, NIPSCO must install additional control equipment, including three new SO_2 control devices and one new NO_x control device. The consent decree also imposes emissions limits for NO_x, SO_2, and PM, and annual tonnage limits for NO_x and SO_2. NIPSCO is in compliance with the terms of the Consent Decree including installation of new air emission controls. Table 8-8 includes a listing of new air emission controls needed to comply with the Consent Decree.

Clean Water Act

The CWA establishes water quality standards for surface waters as well as the basic structure for regulating discharges of pollutants into the waters of the United States. Under the CWA, EPA implemented pollution control programs such as setting wastewater standards for industry, including electric utilities. In addition, the CWA made it unlawful to discharge any pollutant from a point source into navigable waters without a permit. The National Pollutant Discharge Elimination System ("NPDES") permit program implements the CWA's provisions and prohibits unauthorized discharges by requiring a permit for point sources impacting waters of the United States.

CWA 316(b) Cooling Water Intake Structures - Section 316(b) of the CWA requires all large existing steam electric generating stations with cooling water intake structures deploy the best technology available to minimize adverse environmental impacts to fish and shellfish. The EPA's rule implementing Section 316(b) became effective on September 7, 2004. Litigation ensued, and on January 25, 2007, the Second Circuit Court remanded the matter to the EPA to reconsider the options in the regulation that provided for flexibility in meeting the requirements of the rule. Shortly thereafter, the EPA suspended the 316(b) Phase II Rule which governs cooling water withdrawals. The EPA then instructed state and regional regulators implementing Section 316(b) that permits could be issued using best professional judgment to determine the best technology available for reducing adverse environmental impact. Various parties submitted petitions for a *writ of certiorari* to the United States Supreme Court in early November 2007 seeking to reverse the Second Circuit Court's decision. On April 14, 2008, the United States Supreme Court granted the petitions limiting the review to one question. On April 1, 2009, the Supreme Court issued their ruling reversing and remanding the Second Circuit's ruling. The case, *Entergy Corp. v. Riverkeeper, Inc.*, determined that the EPA did not overstep its authority when it adopted national performance standards utilizing cost-benefit analyses. The matter was remanded back to the Second Circuit United States Court of Appeals for further proceedings.

On April 20, 2011, the EPA proposed a rule for existing facilities and new units at existing facilities to codify this approach. The EPA is finalized the rule and published it in the Federal Register on August 15, 2014, with an effective date of October 14, 2014.

The final rule leaves much to the discretion of the state (and the EPA Region that reviews the permit), particularly the entrainment mortality requirements for existing facilities. The rule sets separate standards for impingement mortality and entrainment mortality. Under the final rule, the NIPSCO Michigan City and Schahfer Stations, which have closed cycle cooling systems, may be required to conduct further impingement and entrainment studies, and could be required to install further controls. NIPSCO's Bailly Station, under the final rule which does not have closed cycle cooling, would require more studies including one that takes into consideration nine site specific criteria by which a determination would be made on the intake flow control technology. Likely, modifications to the plant would require an intake velocity reduction to less than 0.5 feet/second and similar changes to the traveling screens coupled with a fish return system.

Electric Steam Power Effluent Guidelines - The EPA in 2009 announced plans to revise the existing Steam Electric Effluent Guidelines affecting electric power plants and, in the process, is focusing on numerous power plant operations, including the effluent generated from coal ash handling systems, metal cleaning operations, wastewater treatment, surface impoundments, landfill operations, and FGD systems used to scrub SO_2 from air emissions. An EPA Information Collection Request ("ICR") to support the rulemaking was received by NIPSCO in mid-June 2010 and has since been completed. The ICR sought information from a wide range of steam electric power generating industry operations in order to characterize waste streams, understand the processes that generate the wastes, gather environmental data, and assess the availability and affordability of treatment technologies.

On June 7, 2013, a proposed rule was published in the Federal Register. The proposed rule named eight possible regulatory options with four preferred that differ in the number of waste streams covered, size of the units controlled, and stringency of controls. The steam electric limitation guidelines are technology-based. The proposed rule establishes new or additional requirements for wastewater stream processes and byproducts associated with steam electric power generation including targeted ELGs pertaining to flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, landfill leachate, and non-chemical metal cleaning waste.

Under the proposed rule, the possible effects of the rule vary from station to station. At the Bailly Generating Station, the wet FGD System will likely require additional modifications to the existing chemical precipitation system at the Pure Air wastewater treatment plant. Additionally, two of the four options would require additional biological treatment in addition to the modifications to the chemical precipitation system. Another waste stream that will likely be affected includes non-chemical metal cleaning waste.

At the Michigan City Generating Station, one of the four preferred options would require bottom ash (boiler slag from Unit 12) to be handled dry/closed loop. Additionally, the boiler's economizer ash may have to be handled dry. Also, non-chemical metal cleaning waste generated at the station would need to be addressed.

At the R.M. Schahfer Generating Station, one of the four preferred options would require bottom ash (Units 15, 17, and 18) and boiler slag (Unit 14) to be handled dry/closed loop. Bottom ash and boiler slag is currently wet sluiced. Additionally, economizer ash may have to be handled dry. The current wet FGD wastewater treatment plant, which was re-constructed for Units 14 and 15, will likely need to be expanded to accept FGD wastewater from Units 17 and 18 or an entirely new wastewater treatment plant may need to be constructed. Additionally two of the four preferred options may require additional biological treatment in addition to the chemical precipitation wastewater treatment systems. Also, non-chemical metal cleaning waste as well as landfill leachate in the future may need to be addressed.

Under the current version of the consent decree, EPA is set to take action and issue final rule by September 30, 2015. In accordance with the proposed rule, portions of the rule would be implemented immediately after the effective date of the rule and upon the renewal of the NPDES permits while other portions of the rule would follow an implementation schedule of July 2017 to July 2022. It is the expectation from EPA in the proposed rule that all facilities will be in compliance with the rule by July 2022. The deadline for compliance will likely be dependent upon each generating station's permit renewal schedule.

Solid Waste Management

On June 21, 2010, the federal government proposed more stringent regulations concerning management and disposal of Coal Combustion Residuals ("CCRs"). The EPA proposal provided two different approaches, both under the RCRA, 1) Subtitle C: a hazardous waste classification or 2) Subtitle D: a non-hazardous waste classification. Both options require new design and monitoring standards for new and existing landfills and surface impoundments and also create dam safety requirements to ensure surface impoundment structural integrity. A consent decree was filed on January 29, 2014, which sets forth EPA's obligation to take final action on the Agency's proposed Subtitle D option by December 19, 2014. Nothing in the consent decree requires the EPA to select the Subtitle D option, but only requires the EPA to make a final decision.

NIPSCO utilizes dry fly ash handling systems for virtually all of its fly ash, with the exception of a small fraction at Michigan City; however, the final ruling has the potential to have a significant impact on NIPSCO related to material handling and disposal. If CCRs are deemed a special waste or hazardous, the cost impact would be significant in both capital expenditures and operations and maintenance costs. If deemed non-hazardous, the cost impact would not be as significant, however, still material.

NIPSCO Emission Allowance Inventory and Procurement Practices

Title IV Acid Rain - SO_2 Emission Allowance Inventory - Under the CAIR SO_2 program, the Title IV (Acid Rain) SO_2 allowances are used on a discounted basis. During the first phase of the CAIR SO_2 program starting in 2010, the acid rain allowances are used at a two to one ratio (25,353 is half of 50,706 or 50 percent value). In conjunction with CAIR, the Title IV Acid Rain Program will continue to regulate emissions. Table 8-1 below lists by year the actual number of SO_2 allowances held in inventory by NIPSCO as of September 2014 for the period 2014 through 2044.

Table 8-1
Acid Rain Program
SO2 Allowance Inventory*

Year	Allowances**
Bank***	103,873
2014	213,393
2015	25,706
2016	36,606
2017	50,706
2018+	50,706
Total	**1,749,506**

CAIR Emission Allowance Inventory

Tables 8-2 and 8-3 lists NO_x annual and ozone season allowance inventory issued to NIPSCO.

Table 8-2
CAIR Annual NO_x Allowance Inventory*

Plant Name	Bank**	2014	Grand Total
Bailly	830	2,599	**3,429**
Mitchell	0	1,760	**1,760**
Michigan City	2,883	2,222	**5,105**
Schahfer	6,716	9,069	**15,785**
Sugar Creek	25	158	**183**
Grand Total	**10,454**	**15,808**	**26,262**

** The table provides the allowance inventory available in September 2014.*

*** Bank reflects emission allowances 2013 or earlier.*

Table 8-3
CAIR NO_x Ozone Season Allowance Inventory*

Plant Name	Bank **	2014	Grand Total
Bailly	2,390	1,141	**3,531**
Mitchell	0	715	**715**
Michigan City	649	1,026	**1,675**
Schahfer	4,159	3,905	**8,064**
Sugar Creek	4	134	**138**
Grand Total	**7,202**	**6,921**	**14,123**

** The table provides the allowance inventory available in September 2014.*

*** Bank reflects emission allowances 2013 or earlier.*

Process Used in Developing NIPSCO's Environmental Compliance Plan

NIPSCO Compliance Planning Process

Since the pace of regulatory change from EPA rulemakings has been and will continue to be highly dynamic, NIPSCO uses a combination of external consulting resources and internal staff to develop and adjust environmental compliance plans. Consultants and architectural and engineering firms are utilized to assist NIPSCO in developing cost estimates and perform modeling of NIPSCO environmental requirements to develop compliance plans to address proposed and expected EPA rules. As the rules change, the plans are adjusted to comply with the new requirements.

Utility MATS

NIPSCO developed a Compliance Plan to address the MATS rule. Since NIPSCO will install FGD equipment on each of the coal-fired units, use of FGD with the co-benefits of HAP removal will be utilized as one tool NIPSCO will use to comply with the MATS. The MATS rule necessitates installation of the Michigan City Unit 12 FGD sooner than the 2018 Consent Decree requirement to meet an in-service date consistent with the timeline established in the MATS rule (i.e., late 2015). While the MATS Compliance Plan will rely on the co-benefits provided by the existing or planned pollution control equipment, each of these units will need additional pollution control installations or projects performed in order to comply with the MATS rule. In summary, the MATS control strategy for mercury consists of design and installation of ACI and fuel additive projects at Units 7, 8, 12, 14 and 15, and for PM the installation of high frequency TR sets on Units 14, 15, 17 and 18. NIPSCO has also identified several incremental O&M projects that are necessary to achieve compliance with the rule including: precipitator and FGD mist eliminator cleaning on Units 7 and 8, electrostatic precipitator flow modeling on Unit 15, and air and water testing at Schahfer Units 14, 15, 17 and 18.

NIPSCO Sustainability Approach

NIPSCO is actively involved in sustainability efforts both in how we do business as well as in the communities we serve. The focus is on finding shared value opportunities with our stakeholders through enhancing the economic, social and environmental way we do business. The four cornerstones of sustainability efforts are to:

- Implement Customer-Focused Energy Solutions
- Promote Strong, Stable Communities
- Steward the Environment
- Assure an Engaged, Aligned and Transparent Approach

Details of NIPSCO's sustainability efforts can be found in the NiSource 2013 Sustainability Report, which can be found at www.nisource.com/sustainability/sustainability-report.

SECTION 9

Resource Alternatives Analysis

In This Section

NIPSCO evaluates viable resource options based on the forecast of customers' needs, the capabilities of its existing resources, and sensitivities to risk to determine the least cost risk-adjusted long term plan. In this section, NIPSCO integrates existing resources, supply side options, renewable options, energy efficiency programs, and DLC programs to evaluate, inform and determine the appropriate long-term plan.

- *Supply-side options and demand-side options are considered on an equal footing.*
- *Plans are tested across scenarios and multiple sensitivities that capture plausible futures and uncertainties to develop a robust and flexible plan.*
- *Sensitivities reflect all reasonably foreseeable outcomes.*
- *The plan is resilient across the scenarios and sensitivities.*
- *The Short-Term Action Plan is derived following integration analysis and risk assessment.*

The NIPSCO Integration Analysis

Integration analysis is the process in which the demand forecast is assimilated with existing owned-generation, demand-side and self-build supply-side options, including renewable and distributed generation. A slate of ranked options is derived that ensures service is provided at the lowest reasonable risk adjusted cost to customers while at the same time satisfying NIPSCO's requirement for the cost effective, compliant, economical, flexible and reliable resource options.

The demand-side and supply-side integration began with twenty-eight (28) options considered for meeting NIPSCO's future requirements. The composition of the options considered was as follows:

- Ten Self-Build Options
- Six Renewable and Distributed Generation Self-Build Options
- Three Existing Resource Retirement Options
- Seven Energy Efficiency Program Options
- Two DLC Program Options

In addition to those options, NIPSCO included 50MW of future distributed generation designed to be as close to market neutral as possible. The distributed generation begins in 2018 and continues throughout the planning horizon.

NIPSCO relied upon the Strategist module PROVIEW™ to systematically explore and evaluate the various combinations of available demand-side and supply-side options to meet NIPSCO's short- and long-term future resource requirements. The plans were subjected to sensitivity and scenario analyses to test the robustness of resource combinations. The integration process results in a ranking of various portfolios, or combination of resource portfolios, based on the optimization of constraints. The resulting plan reflects NIPSCO's full evaluation of all alternative resource strategies.

Data from the supply-side and demand-side options was input directly into PROVIEW to evaluate each of the options head-to-head. The total set of resource options considered for the demand-side and supply-side integration consists of the short-list candidates from the self-build assessment. The options were evaluated with attention to the resource start date for the availability of the resource to meet NIPSCO's demonstrated resource requirements within the decision-making timeframe. The complete list of supply-side and demand-side options evaluated is shown in Table 9-1.

Table 9-1
Summary of Supply-Side and Demand-Side Options

Option	Category	Year First Available
Super Critical Pulverized Coal	Base	2018
IGCC	Base	2019
Advanced Nuclear	Base	2024
Small Modular Nuclear	Base	2021
CCGT	Intermediate	2017
Convert Bailly 7	Intermediate	2017
Convert Schahfer CT's	Intermediate	2017
Conversion CCGT	Intermediate	2017
Large Frame CT	Peaking	2016
Aeroderivative CT	Peaking	2016
Biomass – Stoker Boiler	Renewable	2017
Biomass – Reciprocating	Renewable	2014
Solar Photovoltaic	Renewable	2016
Wind – Onshore	Renewable	2017
Battery	Renewable	2014
Micro Turbines	DG	2014
Bailly 7 Retirement	Retirement	2016
Bailly 8 Retirement	Retirement	2026
Michigan City Retirement	Retirement	2030
Commercial HVAC	EE	2015
Commercial Lighting	EE	2015
Commercial Process	EE	2015
Commercial Other	EE	2015
Residential HVAC	EE	2015
Residential Lighting	EE	2015
Residential Other	EE	2015
Residential AC Cycling	DLC	2015
Industrial DLC	DLC	2015
Future Distributed Generation	DG	2018

The complexity of the resource planning analysis is not apparent at this stage and should be described for a full understanding. Each supply-side and demand-side option is a variable. In addition, its introduction into the resource mix is a variable. The impact of each option multiplies geometrically for each variable for each year the analysis progresses in time. Many other variables impact each option. Each option is then compared against every other option. For illustrative purposes, consider the following, which is based on the methodologies used by NIPSCO in its resource review. Commonly, each resource decision has 2^x options; where the 2 defines the choices, build or do-not-build, and x represents the number of options. For example, a planning decision with five options will generate 2^5 or 32 branches on a decision tree. By Year Two, the decision tree has another geometric progression of 32 branches, 32 times 32 or 1,024 branches. The resource decision cannot be evaluated with regard to only decisions made in Year One. Because the number of resource plans or branches grows exponentially, it is important to establish state space that contains the most economical of the feasible plans. It is estimated that one nonillion (10^{30}) options would result if the options analysis were permitted to run unencumbered, attempting to justify and analyze all alternatives. Such a number is simply unworkable. In other words, every option is not and cannot be reviewed on a blank slate. The important step is to narrow the field, prudently and appropriately, by continually screening the alternatives and setting the optimization constraints in order to focus on the key decisions that are calculated to produce the best, cost effective, least cost integrated resource mix that meets all of NIPSCO's objectives.

Integration Analysis Assumptions

As described above, many variables impact the options and the integration analysis. In order to rationalize both the options and the integration analysis; key assumptions were made about NIPSCO, the MISO market, the demand forecast, and cost inputs. Rationalizing certain assumptions enabled NIPSCO to apply those assumptions consistently to all of the alternatives that were being evaluated.

The options analysis consistently employed a number of key assumptions within the evaluation process. These key assumptions are:

- Economic - Economic assumptions regarding the inflation rate were provided by IHS Global Insight. NIPSCO's capital structure, long-term debt rate, and allowed rate of return on equity were provided from IURC Cause No. 42150-ECR-24 and used to define the after-tax weighted cost of capital, otherwise known as the discount rate.

- Planning Reserves - The planning reserves were targeted at 7.30 percent throughout the IRP period, based on the MISO capacity planning protocol that tracks the reliability of generators by shifting the obligation of system wide reserves to the individual generators. Each generator's ICAP is derated to UCAP. Based upon NIPSCO's generation fleet reliability, MISO's targeted UCAP planning reserve margin of 7.30 percent is equivalent to using an ICAP planning reserve margin of 14.8 percent. The projected forced outage metrics for each of NIPSCO's existing assets were provided by Operations and are consistent with NIPSCO's financial plan. The projected forced outage metrics for the self-build supply-side resources were provided by MISO in their assessment of forced outage metrics for generic units.
- Energy and Demand Forecast - The options analysis adopted the Energy and Demand Forecast, see Section 4.
- Fuel Commodity and Transportation - The options analysis utilized the correlated fuel commodity forecast for coal and natural gas. For natural gas pricing, the natural gas price was assumed at Henry Hub and adjusted for the basis to the Chicago City Gate, plus transportation to burnertip. In order to obtain transportation rates, the pipeline tariff rates, along with storage and balancing rates, were escalated for transportation over time.

For coal pricing, coal site specific costs were assumed at the mine mouth, and incorporated transportation costs to account for benefits or detriments associated with location, i.e., rail or barge. The fuel assumptions are provided in CONFIDENTIAL Appendix I.

- Environmental - The emissions price assumptions for NO_x, SO_2 and CO_2 were provided by PIRA Energy Group. For further information on the environmental forecast see CONFIDENTIAL Appendix I. NIPSCO developed estimates for investments to comply with the EPA's Final Regulations for Cooling Water Intake Structures at Existing Facilities under Section 316(b) of the Clean Water Act, and to comply with pending EPA regulations pertaining to coal ash under subtitle D of RCRA, and with a pending amendment to existing ELG. NIPSCO is in the process of reviewing the EPA's proposed CPP, which is proposing to cut carbon emissions from electric generation by 30% by 2030. A carbon cost has been assumed to be implemented in 2025 to reflect reduced carbon emissions from fossil-fuel generation.
- Energy Market – The energy market forecast, from NIPSCO's energy supply and trading organization, is based on a fully integrated and modeled scenario, taking into account reasoned market trends and public policy decisions regarding climate change and power generation fuel choice. This case represents NIPSCO's official forecast available to all internal stakeholders. NIPSCO's forecast is zonal in nature and the forecast represents the day-ahead energy prices for the Cinergy Hub provide by PIRA Energy Group, adjusted by basis to the NIPSCO load hub. For further information on the energy market forecast see CONFIDENTIAL Appendix I.

  For the market capacity price, NIPSCO used a combination of current futures market prices to reflect near term prices and a long-term forecast of capacity prices at the Cinergy Hub. The NIPSCO's current forecast of capacity prices indicates that capacity is not needed on the MISO market until 2021. The long-term capacity prices were adjusted to reflect the economic carrying charge of NIPSCO's self-build aeroderivative CT to ensure economic consistency of assumptions.
- Operating and Capital Costs - The alternatives analysis incorporates the appropriate inputs regarding operating and capital costs associated with each facility type. The operating constraints for Wind and Solar renewable alternatives considered a typical day operations shape that defined the hourly output of the resource. NIPSCO relied upon historical wind and sun-shine data to derive a typical day shape. Those typical day shapes were used for all future years in the planning horizon.
- Off-System Market - The off-system market is modeled in accordance with MISO's operational model. All generation is sold into the MISO market at the generator hub and all load requirements are purchased from the MISO market at the NIPSCO load hub.
- Regulations - The alternatives analysis incorporated a balanced set of existing and proposed regulations, laws, practices and policies.

The primary assumptions that served as the basis of this IRP appear in Table 9-2.

Table 9-2
Underlying Assumptions

Forecast Item	Percent Compound Annual Growth Rate
60-Minute MW Peak Demand Excluding DSM Effects	
5 year, 2013-2018	0.63%
10 year, 2013-2023	0.62%
20 year, 2013-2033	0.59%
Total MWh Energy Excluding DSM Effects	
5 year, 2013-2018	0.66%
10 year, 2013-2023	0.54%
20 year, 2013-2033	0.46%
Natural Gas Prices for New Units, 2013-2035	4.35%
PRB Coal for New Units, 2013-2035	2.91%
Illinois Basin Coal Prices for New Units, 2013-2035	2.44%
General Inflation Rate Measured by the CPI over, 2013-2035	1.71%
Miscellaneous	**Value**
After-Tax Weighted Cost of Capital	7.68%
Accumulated Funds Used during Construction	7.95%
Effective Income Tax Rate	38.19%
Construction Escalation	3.00%
Minimum Reserve Margin	
2014 through 2035	7.30%
Planning Period (Base Year 2013)	2014-2035
Assumed Availability of Existing Coal-fired Units (years)	60
Assumed Availability of Existing Gas-fired Units (years)	40
Assumed Existing Units Unavailable (calendar year)	
Unit 7	2022
Unit 8	2028
Unit 10	2019
Unit 12	2034

Plan Development

Simulation Computer Model and Techniques

The operational analyses to integrate the supply-side and demand-side resources to formulate NIPSCO's long term plans used a single and fundamental method of analysis – simulation. Unlike the more theoretical process employed through economic derivation, simulation is an analysis that is conducted from the ground up. By contrast, technical analysis is formulaic derivation – one accepts an input variable and then derives an output variable. The simulation method of analysis closely simulates NIPSCO's actual operating environment and is responsive to changes in conditions and variables.

The model simulates the real-world operation of the utility's generation, distribution, and transmission system within an integrated market. The simulation is intended, in each round of alternatives analysis, to determine the cost and reliability effects of adding supply-side and renewable resources to the system or of modifying the load through DSM programs. The dynamic programming methodology limits the total number of options that can be examined at one time within a single analysis, while at the same time allowing for detailed and comprehensive analysis of operational and economic impacts from specific resource options. Careful structuring of the study constraints in conjunction with iterative analysis runs is required. See Appendix D for a description of Strategist and PROVIEW models.

The supply-side and demand-side resources were initially screened on market value. The market value is the value that each of the options would fetch in an open competitive auction setting. Each option was valued using a discounted cash flow. A discounted cash flow analysis uses future free cash flow projections and discounts them, using the after tax weighted cost of capital, to present value terms. The annual cash flow projects include benefits; capacity market revenues and energy market revenue, and costs; asset variable costs, asset fixed costs, and asset capital recovery. Options that pass the initial screening must have a positive market value and a benefit-cost ratio greater than one. The complete list of self-build and demand side options screened are shown in Table 9-3. This is the incremental NPVRR and 2015 programs are included, assuming approved as requested in pending IURC Cause No. 44496.

Table 9-3
Summary of Supply-Side and Demand-Side Options Market Value (2013 NPV K$)

Option	Benefit	Cost	Market Value	Benefit /Cost Ratio
Super Critical Pulverized Coal	$6,520,896	$6,320,812	$200,084	1.03
IGCC	$5,663,884	$5,974,880	($310,996)	(0.95)
Advanced Nuclear	$16,566,347	$15,232,572	$1,333,776	1.09
Small Modular Nuclear	$5,505,930	$4,606,362	$901,568	1.20
CCGT	$7,813,359	$1,970,104	$5,843,254	3.97
Convert Bailly 7[5]	$5,985,217	$1,372,515	$4,612,702	4.36
Convert Schahfer CT's	$2,435,777	$760,683	$1,675,093	3.20
Conversion CCGT	$7,749,743	$2,162,218	$5,587,525	3.58
Large Frame CT	$2,193,232	$469,424	$1,723,808	4.67
Aeroderivative CT	$257,447	$187,340	$70,098	1.37
Biomass – Stoker Boiler	$1,316,089	$1,228,053	$88.036	1.07
Biomass – Reciprocating	$908,092	$905,208	$2,884	1.00
Solar Photovoltaic[6]	$89,254	$230,688	($141,435)	(0.39)
Wind – Onshore	$588,992	$559,992	$28,447	1.05
Battery	$108,002	$583,263	($475,261)	(0.19)
Micro Turbines	$293,028	$589,866	($296,838)	(0.50)
Bailly 7 Retirement[7]	$89,873	$344,125	($254,252)	(0.26)
Bailly 8 Retirement[8]	$139,868	$449,880	($310,012)	(0.31)
Michigan City Retirement[9]	$12,682	$180,247	($167,565)	(0.07)
Commercial HVAC	$44,854	$104,763	($59,908)	(0.43)
Commercial Lighting	$225,014	$93,575	$131,439	2.40
Commercial Process	$106,364	$87,116	$19,248	1.22
Commercial Other	$54,247	$15,299	$38,948	3.55
Residential HVAC	$10,930	$63,835	($52,905)	(0.17)
Residential Lighting	$39,841	$34,224	$5,617	1.16
Residential Other	$37,628	$61,207	($59,909)	(0.61)
Residential AC Cycling	$209,343	$10,805	$198,538	19.37
Industrial DLC	$1,520,297	$143,852	$1,376,446	10.57
Distributed Generation	$34,789	$29,701	$5,088	1.17

[5] The Bailly 7 conversion only includes the new technology and does not include the early retirement requirements for the Bailly 7 unit.
[6] Solar Photovoltaic is defined by a declining capital escalation demonstrating future market economics driving down the cost of installation.
[7] Earliest Retirement date is 2016.
[8] Earliest Retirement date is 2016.
[9] Earliest Retirement date is 2030.

Using the dynamic programming logic of PROVIEW, NIPSCO evaluates combinations of available Supply-Side and Demand-Side resource alternatives, called states, in each year of the 20-year planning period. Each year's feasible states, those states passing all of Strategist's study constraints, are used as the basis for generating new combination of options in the next year of alternatives. When the final year of the planning period has been analyzed, the states are back-traced to determine the timing of the resource additions. The back-traced analyses become the plans that PROVIEW will rank according to the NPVRR. The revenue requirement in this usage includes both the operational costs such as fuel and O&M, incremental capital costs associated with new construction, and capital costs associated with the existing system. All feasible plans that pass Strategist's constraints are ranked in descending order of NPVRR.

The basis for determining the ranking of the NPVRR of a mix of resources is established in Strategist using its expansion planning module, PROVIEW. In these simulations, the model examines the impact on the utility. NIPSCO used the following strategy to determine the optimal plans.

1. Identify the optimal self-build plan using only aeroderivative CTs, frame CTs and CCGT resources ("Gas Plan").
2. Model the DSM options, excluding the Industrial DLC, to determine the optimal mix of DSM and gas resources ("DSM/Gas Plan"). NIPSCO has determined that the Industrial DLC would be considered as a separate scenario, thereby identifying the optimal plan with and without Industrial DLC ("DSM/Gas/DLC Plan").
3. Model the coal and nuclear assets to determine if these assets bring value to the NIPSCO system ("DSM/Non-Gas Plan").
4. Model the renewable assets to determine if these assets bring value to the NIPSCO system ("DSM/Gas/Renewable Plan" and "DSM/Renewable Plan").
5. Model units' early retirements to determine if an economic advantage potentially exists for early retirement.

NIPSCO Simulation Runs for Alternatives Analysis

As a first step, a reference case was developed with only self-build supply-side peaking and intermediate options through PROVIEW based upon the 2014 IRP Demand and Energy Forecast. These plans considered the aeroderivative CTs, frame CTs, CCGT, and the three CCGT conversion options. The resulting plan demonstrated an NPVRR of $11,629,661 (2013 K$) and the expansion plan building a CCGT in 2023 followed by another CCGT in 2035. Table 9-4 defines the expansion plan.

Table 9-4
Gas Plan

Year	Plan Additions	MW
2014		
2015		
2016		
2017		
2018		
2019	Retire Bailly 10	(31)
2020		
2021	Market Purchase	19
2022	Retire Bailly 7	(160)
	Market Purchase	48
2023	CCGT 1	660
2024		
2025		
2026		
2027		
2028	Retire Bailly 8	(320)
2029	Market Purchase	20
2030	Market Purchase	40
2031	Market Purchase	56
2032	Market Purchase	72
2033	Market Purchase	105
2034	Retire Michigan City 12	(469)
	Market Purchase	122
2035	CCGT 2	660

The primary driver of resource additions is the retirement of existing generation assets. The plan calls for the first CCGT immediately following the retirement of Bailly 7 and a second CCGT following the retirement of Michigan City 12.

The second step included all seven DSM programs and the Residential AC Cycling program. This optimization considered all of the DSM options on an equal footing with supply-side options. The DSM programs selected include Commercial Lighting, Commercial Other, Commercial Process, Residential Lighting, and the Residential AC Cycling. The DSM programs rejected include Commercial HVAC, Residential HVAC and Residential Other. The resulting plan demonstrated an NPVRR of $11,304,097 (2013 K$) and the following expansion plan building a CCGT in 2023 followed by another CCGT in 2035. Table 9-5 defines the expansion plan.

Table 9-5
DSM/Gas Plan

Year	Plan Additions	MW
2014		
2015	DSM Programs	126.5[10]
2016		
2017		
2018		
2019	Retire Bailly 10	(31)
2020		
2021		
2022	Retire Bailly 7	(160)
2023	CCGT 1	660
2024		
2025		
2026		
2027		
2028	Retire Bailly 8	(320)
2029		
2030		
2031		
2032		
2033		
2034	Retire Michigan City 12	(469)
2035	CCGT 2	660

The inclusion of DSM resource in the portfolio effectively eliminated the need for external market capacity purchases. The resulting plan continues to be driven by the retirement of existing generation assets. The inclusion of DSM programs resulted in an overall savings of $325,564 (2013 K$).

The third step evaluated the inclusion of base load resource, i.e., coal, nuclear, and IGCC. In this optimization, no plan selected a base load resource prior to the 2035 CCGT 2. For comparison purposes, a sub-optimal plan was created that replaced the near term, 2023, CCGT with a supercritical pulverized coal unit. The resulting plan demonstrated an NPVRR of $14,380,881 (2013 K$) and the following expansion plan builds a SCPC in 2023 followed by a CCGT in 2035. Table 9-6 defines the expansion plan.

[10] Average Peak reduction over the planning horizon.

Table 9-6
DSM/Non-Gas Plan

Year	Plan Additions	MW
2014		
2015	DSM Programs	126.5[11]
2016		
2017		
2018		
2019	Retire Bailly 10	(31)
2020		
2021		
2022	Retire Bailly 7	(160)
2023	SCPC	577
2024		
2025		
2026		
2027		
2028	Retire Bailly 8	(320)
2029		
2030		
2031		
2032		
2033		
2034	Retire Michigan City 12	(469)
2035	CCGT 1	660

The inclusion of other base load resources added no value to the NIPSCO portfolio and resulted in an increased cost of $3,076,785 (2013 K$) over the DSM/Gas Plan. No further consideration was given for other base load generating assets.

The fourth step evaluated the inclusion of renewable resources. In this optimization, no plan selected a renewable resource prior to the 2032 and none of the renewable options were economically sufficient to defer the need for a CCGT. The highest ranked plan that included renewable resources included wind and photovoltaic resource added after 2032. The resulting plan demonstrated an NPVRR of $11,404,807 (2013 K$) and the following expansion plan builds additional renewable capacity including a wind asset in 2033 and photovoltaic assets in 2033 and 2034. Table 9-7 defines the expansion plan.

[11] Average Peak reduction over the planning horizon.

Table 9-7
DSM/Gas/Renewable Plan

Year	Plan Additions	MW
2014		
2015	DSM Programs	126.5
2016		
2017		
2018		
2019	Retire Bailly 10	(31)
2020		
2021		
2022	Retire Bailly 7	(160)
2023	CCGT 1	660
2024		
2025		
2026		
2027		
2028	Retire Bailly 8	(320)
2029		
2030		
2031		
2032		
2033	On Shore Wind	22.6[12]
	Photovoltaic	0[13]
2034	Retire Michigan City 12	(469)
	Photovoltaic	0
2035	CCGT 2	660

The inclusion of renewable resources added no value to the NIPSCO portfolio and resulted in an increased cost of $100,710 (2013 K$) over the Gas/DSM Plan. NIPSCO further investigated the impact of renewables by constraining the model to select no gas resources and meet all future needs with renewable assets only. The resulting plan demonstrated an NPVRR of $17,264,272 (2013 K$). Table 9-8 defines the expansion plan.

[12] Nominal wind resource is 160 MW with a UCAP of 22.56 MW
[13] Nominal photovoltaic resource is 100 MW with a UCAP of 0.0 MW

Table 9-8
DSM/Renewable Plan

Year	Plan Additions	MW
2014		
2015	DSM Programs	126.5
2016		
2017		
2018		
2019	Retire Bailly 10	(31)
2020		
2021		
2022	Retire Bailly 7	(160)
2023	On Shore Wind	565
2024		
2025		
2026		
2027		
2028	Retire Bailly 8	(320)
2029	Biomass	91.1
	Market Purchase	12
2030		
2031	Market Purchase	9
2032	Market Purchase	16
2033	Market Purchase	99
2034	Retire Michigan City 12	(469)
	Market Purchase	65
2035	On Shore Wind	678
	Market Purchase	123

The inclusion of an all renewable resource plan provide no value to the NIPSCO portfolio and resulted in an increased cost of $5,960,175 (2013 K$) over the Gas/DSM Plan.

The fifth step examined the impact of early retirements for Bailly 7, Bailly 8, and Michigan City 12, both individually and in combination. None of the early retirement plans demonstrated any value to the NIPSCO portfolio.

The prominent feature of all the explored plans was the inclusion of a near-term CCGT. NIPSCO made one final analysis to determine the viability of the CCGT conversions to determine if either the Bailly 7 conversion or the Schahfer 16 A&B conversions offered greater economic value to its customers. The expansion plans are compared in Table 9-9.

Table 9-9
Comparison of CCGT Conversion Plans

Year	Plan Additions	MW	Plan Additions	MW
2014				
2015	DSM Programs	126.5	DSM Programs	126.5
2016				
2017				
2018				
2019	Retire Bailly 10	(31)	Retire Bailly 10	(31)
2020	Retire Bailly 7	(160)	Retire 16 A&B	(158)
2021	Market Purchase	89	Market Purchase	77
2022	Market purchase	105	Retire Bailly 7	(160)
			Market Purchase	93
2023	Bailly 7 Conv.	580	Sch. 16 Conv.	287
2024				
2025				
2026			Market Purchase	10
2027			Market Purchase	19
2028	Retire Bailly 8	(320)	Retire Bailly 8	(320)
			Market Purchase	29
2029			CCGT	660
2030				
2031				
2032				
2033				
2034	Retire Michigan City 12	(469)	Retire Michigan City 12	(469)
2035	CCGT	660	CCGT	660

The DSM/Gas plan, with two CCGTs, demonstrated a NPVRR of $11,304,097 (2013 K$). Since there was no demonstrated value to adding a single stand-alone frame CT prior to the need for a CCGT in 2023, NIPSCO did not investigate a conversion CCGT. Building a conversion CCGT, as opposed to the designed CCGT, carries a premium in development costs of $172,880 (2013 K$). The conversion of Bailly 7 offers slightly less capacity and increases NPVRR by $53,030 (2013 K$). The Schahfer 16A&B conversion provides significantly less capacity. The result is a need for an additional CCGT in 2029. The conversion of Schahfer 16A&B increases NPVRR by $175,680 (2013 K$). Based upon this analysis, NIPSCO will not go forward with any of the CCGT conversion projects.

The final scenario included the potential for incremental Industrial DLC, defined as curtailment and short notice interruptions with at least ten minutes notice. Curtailments were assumed to be unlimited as to quantity and duration, and interruptions limited to no more than one per day, no more than 12 consecutive hours, no more than three consecutive days during weekdays, and no more than 200 hours per rolling 365 days. The addition of 122.9 MW of industrial DLC resulted in an NPVRR of $11,224,543 (2013 K$). Table 9-10 defines the expansion plan.

Table 9-10
DSM/Gas/DLC Plan

Year	Plan Additions	MW
2014		
2015	DSM Programs	126.5
	Industrial DLC	122.9
2016		
2017		
2018		
2019	Retire Bailly 10	(31)
2020		
2021		
2022	Retire Bailly 7	(160)
2023		
2024		
2025	Market Purchase	1
2026	Market Purchase	12
2027	Market Purchase	22
2028	Retire Bailly 8	(320)
	Market Purchase	32
2029	CCGT 1	601
2030		
2031		
2032		
2033		
2034	Retire Michigan City 12	(469)
2035	CCGT 2	601

The inclusion of incremental Industrial DLC defers the first CCGT from 2023 to 2029 and represents an aggregate savings of $79,554 (2013 K$).

Table 9-11 shows the following quantitative elements from the selected plans.

- Cost of operations and environmental regulations compliance of the existing units and the cost of net market interchange
- Cost of operations for planned additions
- Cost of capital for planned additions
- Total revenue requirements
- Average incremental cost per kilowatt-hour for the plans, but does not include the present NIPSCO rate base
- Average marginal cost to serve the next incremental MW of load
- Breakdown of equity and debt for all capital expenditures for planned additions
- Energy mix for coal, gas, renewable, DSM and net market

All dollar figures are represented in 2013 K$. The analysis was conducted using the set of assumptions identified in the Slow Economic Improvement Scenario, considered NIPSCO's base case assumptions. The lowest cost expansion plans, were DSM/Gas/DLC and DSM/Gas with incremental NPVRR values of $11,224,543 and $11,304,097 respectively. Since the potential to increase Industrial DLC, characterized as unlimited curtailments and short notice interruptions, is unknown at this time, the DSM/Gas plan was designated the base case.

Table 9-11
Summary of Alternatives Analysis

	Gas Plan	DSM/ Gas Plan (Base Case)	DSM/ Non-Gas Plan	DSM/Gas/ Renewable Plan	DSM/ Renewable Plan	DSM/Gas/ DLC Plan
Operating Costs (2013 K$)						
Existing Units	$9,711,674	$9,146,619	$9,368,278	$9,120,469	$5,897,040	$9,506,933
Planned Additions	$622,841	$621,307	$846,401	$620,960	$88,136	$311,584
Capital Costs (2013 K$)	$1,295,145	$1,536,170	$4,166,202	$1,663,378	$11,279,095	$1,406,027
Total Revenue Requirements (2013 K$)	$11,629,661	$11,304,097	$14,380,881	$11,404,807	$17,264,272	$11,224,543
Average Incremental Cost (2013 $/kWh)	53.92	53.63	68.23	54.11	81.91	53.26
Average Avoided Cost (2013 $/kWh)	68.65	68.65	68.66	68.65	68.41	68.59
Utility Investment						
Equity (2013 K$)	$414,359	$414,359	$1,689,800	$593,096	$7,376,615	$164,900
Debt (2013 K$)	$263,141	$263,141	$1,073,117	$376,649	$4,684,561	$104,721
Energy Mix						
Coal	43%	43%	47%	43%	30%	44%
Gas	17%	15%	10%	15%	7%	13%
Renewable	2%	2%	2%	3%	51%	2%
DSM	1%	4%	4%	4%	4%	4%
Market	37%	36%	37%	36%	7%	37%

Sensitivities and Scenarios Analysis

To evaluate the risk associated with market uncertainty, NIPSCO developed two scenarios with various deterministic sensitivity analyses. The first scenario, "Slow Economic Improvement," is considered NIPSCO's base case. The second scenario, "Aggressive Environmental Regulations" is a future where environmental regulations are increased and a renewable portfolio standard is introduced. The assumptions for each scenario can be seen in Table 9-12. The purpose of establishing a base case analysis is to reflect NIPSCO's current view of the future market, taking into account all reasonably foreseeable outcomes. It should be noted that the impact of a future Federal mandate to reduce carbon is included in the base case. The sensitivity analyses are performed in order to see how the various resource options will rank when different assumptions in key variables are assumed.

Table 9-12
Scenario Assumptions

Drivers	Units	Slow Economic Improvement	Aggressive Environmental
Natural Gas	($/MMBtu)	4.54 @ 5%	5.85 @ 4.9%
Electricity	($/MWh)	On-Peak 37.99 @ 5.6% Off-Peak 26.91 @ 6.0%	On-Peak 48.40 @ 6.3% Off-Peak 34.32 @ 6.9%
316(b), ELG, CCR	($)	44M, 178M, 79M	64M, 461M, 106M
Carbon	($/ton)	20.00 (2025)	20.00 (2020)
RPS	(%)	NA	15 (2020)
Peak	(MW)	3,209 @ 0.9%	3,209 @ 0.9%
Energy	(GWh)	18,275 @ 0.5%	18,275 @ 0.5%

Another analytical process available to NIPSCO for sensitivity analyses is stochastic or Monte Carlo analysis. Monte Carlo algorithms are based on random sampling of input variable to simulate their impact on operational results. Monte Carlo is generally applied when it is infeasible to compute an exact result using deterministic methods. The major issue with Monte Carlo analysis of utility operations is the problem that erroneous data input will result in erroneous data output. Monte Carlo requires probability distributions over the range of possible inputs. The major requirement of Monte Carlo analysis is a large number of input iterations; the approximation improves with more data. Another key issue with Monte Carlo analysis is the interaction of variables or intra-variable correlations. Monte Carlo requires sound probability distributions and intra-variable correlation to produce thousands of possible outcomes. The results are then statistically analyzed to determine the probabilities of different outcomes. By contrast, NIPSCO has elected to use a deterministic approach using single point estimates; expected, best, and worst for input variables, including intra-variable correlation. NIPSCO believes that a deterministic approach is the most cost-effective approach to quantifying risk.

Description of Slow Economic Improvement ("Base Case") - The Base Case for the 2014 IRP was based on a best reasonable projection or expected case view of future economic, demographic and energy use conditions. These assumed conditions are best described as representing a P50, 50th percentile or average, view of the future. In addition, a carbon cost is assumed to be implemented in 2025.

Description of Aggressive Environmental Regulations - The second scenario developed for the 2014 IRP assumed higher commodity prices, a renewable portfolio standard implemented in 2020, higher costs to comply with pending EPA regulations and a carbon cost is assumed to be implemented in 2020.

Tested Sensitivity - High and Low Load Growth - The high and low sensitivity data was developed on load growth. Analysis for demand and energy was based on a load forecast provided by NIPSCO's Forecasting Group. The high load growth represented an approximate increase in demand and energy by seven to nine percent. The low load growth represented an approximate decrease in demand and energy by five percent. The load growth sensitivities are presented in CONFIDENTIAL Appendix I.

Tested Sensitivity - High Construction Escalation - High construction escalation sensitivity assumed a capital escalation rate of five percent. A low case was not conducted because low price escalation is not of concern.

Tested Sensitivity – High and Low Commodity Market Conditions - The high and low market conditions forecasts were driven by assumed changes in the natural gas market, provided by NIPSCO, and correlated to the corresponding external energy market. The high commodity market conditions represent a 28 percent increase in natural gas prices and a 35 percent increase in escalation. The low commodity market conditions represent a 71 percent decrease in escalation. The charts related to these sensitivities are found in CONFIDENTIAL Appendix I.

Tested Sensitivity – No Carbon - The no carbon sensitivity assumed a delay in implementing a carbon cost beyond the study horizon of 2035. The revised external market prices are presented in CONFIDENTIAL Appendix I. The delay of implementing a carbon cost does not affect NIPSCO's expansion plan. The optimal plan, with and without a carbon cost modeled, demonstrated an equal need for a CCGT in 2023 and 2035

Tested Sensitivity – Aggressive Regulation – The aggressive regulation sensitivity assumes stricter EPA guidelines for CCR rules, ELG, and Cooling Water Intake rules ("316b"). Under the aggressive regulation; CCR regulatory costs are 34 percent higher, ELG regulatory costs are 159 percent higher, and 316b regulatory costs are 45 percent higher.

The following plans were subjected to these sensitivities: Gas Only, DSM/Gas, and DSM/Gas/Renewables. The results are in Table 9-13.

Table 9-13
Tested Sensitivity Results

Sensitivity	Gas	Delta	DSM/Gas	Delta	DSM/Gas/ Renewable	Delta
High Load Growth	$14,216,900	22%	$13,197,260	17%	$13,281,180	16%
Base Case	$11,629,661		$11,304,097		$11,404,807	
Low Load Growth	$10,792,040	7%	$10,693,320	5%	$10,794,000	5%
High Construction Escalation	$11,769,380	1%	$11,399,740	1%	$11,551,710	1%
Base Case	$11,629,661		$11,304,097		$11,404,807	
High Commodity Market	$12,190,940	5%	$11,684,060	3%	$11,752,910	3%
Base Case	$11,629,661		$11,304,097		$11,404,807	
Low Commodity Market	$10,625,190	9%	$10,389,170	8%	$10,506,900	8%
Base Case	$11,629,661		$11,304,097		$11,404,807	
No Carbon	$9,806,315	16%	$9,556,280	15%	$9,671,133	15%
Aggressive Regulation	$11,937,180	3%	$11,611,600	3%	$11,712,330	3%
Aggressive Environmental	$13,646,080	17%	$13,548,530	20%	$13,671,610	20%
Base Case	$11,629,661		$11,304,097		$11,404,807	

The bounds around the sensitivities indicate that NIPSCO's risk exposure is consistent across the plans. The plans with DSM provide the better hedge against risk of load growth, commodity risk, and carbon implementation risk. All of the plans are equally affected by high construction escalation and aggressive regulation.

Operational Analysis

As part of its ongoing planning process, NIPSCO evaluates the competitiveness of all existing assets. The complete list of NIPSCO existing assets are shown in Table 9-14.

Table 9-14
Existing Assets Market Value
(2013 K$)

Asset	Benefit	Cost	Market Value	Benefit/ Cost Ratio
Sugar Creek	$8,299,699	$1,228,782	$7,070,917	6.75
Bailly 7	$1,218,160	$328,537	$889,623	3.71
Bailly 8	$3,767,024	$929,190	$2,837,834	4.05
Michigan City 12	$6,969,929	$1,263,233	$5,706,696	5.52
Schahfer 14	$6,333,605	$1,162,884	$5,170,721	5.45
Schahfer 15	$7,033,372	$1,147,924	$5,885,448	6.13
Schahfer 17	$5,468,182	$986,538	$4,481,645	5.54
Schahfer 18	$5,525,160	$1,015,160	$4,509,412	5.44
Schahfer 16A	$863,462	$16,572	$846,890	52.10
Schahfer 16B	$863,462	$16,572	$846,890	52.10
Bailly 10[14]	$65,016	$1,381	$63,635	47.07
Norway Hydro	$52,647	$25,457	$27,191	2.07
Oakdale Hydro	$74,391	$17,491	$56,900	4.25
Wind PPA	$151,571	$135,829	$15,742	1.12
Large FIT Biomass	$145,777	$147,870	($2,093)	(0.99)
Large FIT Solar	$62,688	$81,746	($19,058)	(0.77)
Large FIT Wind	$99	$179	($80)	(0.55)
Small FIT Solar	$3,672	$4,553	($881)	(0.81)
Small FIT Wind	$23	$38	($16)	(0.59)
Industrial DLC	$5,342,809	$500,813	$4,841,886	10.67

Results of the Integration Process

NIPSCO has undertaken a thorough evaluation of its resource options for current and future planning. NIPSCO integrated its demand-side energy efficiency programs, DLC programs, and self-build supply-side resource options to determine the appropriate Short-Term Action Plan. NIPSCO's Short-Term Action Plans calls for implementation of five DSM energy efficiency programs, one residential DLC program, and potentially one Industrial DLC program. The need in the longer term is one CCGT in 2023 and one CCGT in 2035.

[14] Does not include the value of Black Start capability

SECTION 10

Transmission and Distribution

In This Section

NIPSCO continues to invest in its existing T&D resources to ensure the safe and reliable service to its customers. NIPSCO continually assesses the current physical T&D system resources for needed improvements and upgrades to meet future customer demand or other changing conditions. As part of this effort, NIPSCO participates in the planning processes at state and regional levels to ensure that its customers' interests are fully represented and to coordinate its planning efforts with others. This planning process is open and transparent. The goals of the planning process include:

- *Adequately serve native customer load and maintain continuity of service to customers under various system contingencies.*
- *Proactively maintain and increase availability and reliability of the electric delivery system.*
- *Minimize capital and operating costs while being consistent with the above guidelines.*
- *NIPSCO continues to invest in its T&D resources to ensure safe, reliable, and economic delivery of electric energy from generating facilities to its customers.*
- *NIPSCO transmission planning is in compliance with the transmission planning standards mandated by FERC through the NERC Transmission Planning ("TPL") standards.*
- *NIPSCO coordinates its transmission planning with other utilities in a broader regional transmission planning effort through its participation in the open and transparent planning processes at the MISO. NIPSCO also actively participates in the reliability and economic planning studies of PJM Interconnection due to the interconnected nature of the NIPSCO and PJM companies' system.*
- *NIPSCO is executing its two Multi-Value Projects ("MVP") approved by the MISO Board in 2011.*
- *NIPSCO distribution planning analyzes reliability metrics and loading on its distribution facilities, and identifies the need for upgrades to support customer load growth and to address age and condition of existing facilities.*
- *NIPSCO has established a seven-year plan to modernize its T&D infrastructure also known as TDSIC, or NIPSCO's Electric Infrastructure Modernization Plan further defined in its approved filing in Cause No. 44370.*
- *NIPSCO continuously monitors industry and academic developments for improvements in technology and software related to T&D.*

Transmission System Planning Criteria and Guidelines

NIPSCO's Transmission System Planning Criteria requires analysis of the adequacy of system reliability for the outage of various system components including, but not limited to generators, lines, transformers, substation bus sections, substation breakers, and double-circuit tower lines. Adequacy is measured in terms of NIPSCO design voltage, thermal requirements, fault interrupting capability, and generator rotor angle stability documented in the NIPSCO 2014 FERC Form 715 (CONFIDENTIAL Appendix H). When a violation of one or more of these requirements is identified, Transmission Planning develops mitigations that may consist of operating measures and/or system improvements.

NERC

NIPSCO is subject to the mandatory reliability standards of NERC whose mission is to ensure the reliability of the North American bulk electric system. NERC is the Electric Reliability Organization certified by FERC to establish and enforce its reliability standards for the bulk-electric system. NIPSCO is registered with NERC as a Load Serving Entity, Resource Planner, Transmission Planner, Generator Owner, Generator Operator, and Distribution Provider. Together with MISO in a Coordinated Functional Registration, NIPSCO is registered as a Transmission Owner, Transmission Operator, and Balancing Authority. Each registered entity is subject to compliance with applicable NERC standards, and ReliabilityFirst RRO standards approved by FERC. Non-compliance with these standards can result in potential fines or penalties.

MISO

NIPSCO participates in the larger regional transmission planning processes through participation in MISO. MISO annually performs a planning analysis of the larger regional transmission system through the Midcontinent Transmission Expansion Plan ("MTEP"). The MTEP process identifies reliability adequacy on a larger regional basis and ensures that the transmission plans of each member company are compatible with those of other companies.

Requests by generation owners to connect new generators to the NIPSCO transmission system, to change the capacity of existing generators connected to the NIPSCO transmission system, or otherwise modify existing generators connected to the NIPSCO transmission system are handled through the MISO Generation Interconnection ("GI") Process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

Requests by generation owners to secure transmission service are handled through the MISO Transmission Service Request ("TSR") process. NIPSCO participates in this effort to review potential impacts on the NIPSCO transmission system and identify improvements or upgrades necessary to accommodate these requests.

Because NIPSCO is situated on a very significant seam (boundary) between MISO and PJM, NIPSCO participates in the coordination of transmission planning efforts between MISO and PJM under the MISO-PJM Joint Operating Agreement ("JOA").

In addition, MISO may propose transmission system projects or other upgrades that are not reliability-based, but are economically based and should relieve congestion. These projects must pass the Benefit Cost Ratio ("BCR") test established by MISO before approval. NIPSCO participates in this effort through the MISO Market Efficiency Planning Study ("MEP"), and the MISO-PJM Interregional Planning Stakeholder Advisory Committee ("IPSAC") which performs a coordinated system planning study with PJM.

Although unrelated to MISO, NIPSCO also participates in the PJM Market Efficiency Planning Study.

In addition to being active in planning activities, NIPSCO is also active in other stakeholder groups at MISO. NIPSCO is a very active participant in the Transmission Owners and Stakeholder process. Since NIPSCO's last IRP, the MISO South Region, including Entergy, has been integrated into the MISO footprint. First Energy Corporation left MISO effective June 1, 2011, and Duke Energy - Ohio and Duke Energy - Kentucky left MISO effective December 31, 2011. Duke Energy - Indiana has remained in MISO.

Given pending environmental regulations a tighter balance between supply and demand in the MISO market is anticipated to lead to a requirement for higher reserve margins in the next two years, potentially increasing NIPSCO's resource requirements.

NIPSCO currently holds Chair or Vice Chair positions in the following MISO Stakeholder community:

- Market Subcommittee
- Stakeholder Governance Working Group
- Supply Adequacy Working Group
- Data Transparency Working Group

NIPSCO continues to actively participate in the Reliability Subcommittee, Market Subcommittee, and all related working groups and task teams. In addition to being a Transmission Owner, NIPSCO has representation in the Power Marketers Sector.

NIPSCO is a very active participant in the Balancing Authority Committee and Balancing Authority Task Teams. Through these groups, NIPSCO monitors and assists MISO as they perform their task as the Balancing Authority, ensuring reliability and NERC compliance.

NIPSCO is an active member of the Transmission Owners Committee and all of its related working groups and task teams, as well as MISO committees dealing with transmission policy such as the Regional Expansion Criteria and Benefits Task Force and the Candidate MVP Technical Studies Task Force.

NIPSCO is active in the Planning Advisory Committee, the Planning Subcommittee and other related Subcommittees, working groups and task teams.

Through participation in the Stakeholder process, NIPSCO continues to support MISO's efforts to improve efficiency and operations in the Reliability footprint and Market footprint. NIPSCO continues to work with MISO to develop market tools that support and/or enhance reliability and the benefits to NIPSCO customers and shareholders.

Market Participants

Market participants have the ability to voluntarily fund upgrades on the NIPSCO transmission system through the MISO planning processes to better accommodate their generation outlet capacity, increase their financial transmission hedging, congestion reduction, or other considerations. NIPSCO has participated in three of these voluntary upgrade agreements with market participants through the MISO process.

Customer-Driven Development Projects

NIPSCO may be contacted by individual customers based on the customer's plans for economic development or expansion. In coordination with the customer, NIPSCO Major Accounts, and NIPSCO Economic Development, transmission upgrades are identified as necessary to meet the customers' development or expansion plans.

Infrastructure Modernization

The TDSIC is an initiative to modernize infrastructure through rebuilding and upgrading the NIPSCO electric and natural gas delivery system. For the electric system, this includes eligible upgrades to overhead lines, underground lines, conduit, poles, circuits, protective relaying, substations, and other equipment over a seven-year period. The methodology for project selection and NIPSCO Electric Infrastructure Modernization Plan are described in NIPSCO's approved filing in Cause No. 44370.

Transmission System Performance Assessment

NIPSCO's 2014 FERC Form 715 Annual Transmission Planning and Evaluation Report filing (CONFIDENTIAL Appendix H), Part 2 contains the regional power flow cases, available through the ReliabilityFirst. The cases include solved real and reactive flows, voltages, detailed assumptions, sensitivity analyses and model description. Part 3 includes applicable transmission maps. Part 4 describes the reliability criteria used for transmission planning. Part 5 presents the assessment practice used. Part 6 contains an evaluation of the reliability criteria in relation to the present performance and the expected performance of the NIPSCO transmission system.

System Operations - System Improvements

In March of 2014, MISO and its members completed the installation phase of the MISO Synchrophasor project. The original MISO project, done in conjunction with DOE, called for the installation of 150 Phase Measurement Units ("PMU") and 12 Phasor Data Collectors ("PDC"). As more DOE funds became available, more units were installed. With installation now complete, there are now 260 PMU and 40 PDCs that were done under the DOE grant. NIPSCO has eight PMUs and three PDCs on its system. MISO continues to work on the development of Real Time Situational Awareness, Event Analysis, and Model Validation tools. NIPSCO continues to support and participate in the Synchrophasor project with MISO. NIPSCO also continues to participate in the Frequency Monitoring Network project, a North America-wide frequency tracking project under another DOE sponsored grant.

NIPSCO Transmission System Capital Projects

NIPSCO's portfolio of transmission system projects has been identified beginning with the annual transmission system performance assessment to establish base line reliability projects. This portfolio has been expanded to include transmission projects initiated by market participants, by customer driven development projects, and to include regional transmission projects designated as MVP identified through the MISO MTEP planning effort in 2011. This portfolio presently includes the following projects in kilovolts ("kV"):

- Enbridge 138-12 kV customer substation addition – (in-service) $4,978,836
- Magnetation 138-69 kV customer substation addition – (in-service) $7,251,214
- Valparaiso 138-69 kV bulk electric substation addition - $10,927,582
- East Winamac-Monticello 138 kV line upgrade - $10,454,646
- Goodland-Remington-Honey Creek 69 kV line upgrade - $69,342,133
- MVP 12: A new NIPSCO 345 kV circuit from Reynolds to Burr Oak to Hiple substations - $271,000,000
- MVP 14: A new NIPSCO and PIONEER Transmission LLC jointly-owned 765 kV circuit from the Duke Greentown substation to the NIPSCO Reynolds substation - $328,708,150

Evolving Technologies and System Capabilities

NIPSCO is monitoring developments in high voltage direct current ("HVDC") technology and the potential role it may play in the planning of future transmission systems and providing access to diverse energy resources. Clean Line Energy Partners LLC ("Clean Line") has several projects under development in the U.S. In the order issued in IURC Cause No. 44264 on May 22, 2013, Grain Belt Express Clean Line LLC was determined to be a public utility within the meaning of Ind. Code § 8-1-2-1, and an energy utility within the meaning of Ind. Code § 8-1-2.5-2. Interconnection studies are underway at both MISO and PJM for several Clean Line projects through the Midwest, most of which will impact the NIPSCO transmission system. It is NIPSCO's understanding that Clean Line intends to increase market access to low-cost, high capacity factor wind resources with these projects.

Distribution Planning

NIPSCO's distribution system is analyzed for local circuit, substation and source feed adequacy. Normal operating status as well as single element failure (first contingency) condition loading and voltage operating characteristics are evaluated along with specific circuit and system-wide reliability metrics (i.e. customer average interruption duration index, system average interruption duration index, system average interruption frequency index). System improvement plans are typically developed and based upon mitigation of deficiencies associated with service capacity, service voltage, load growth and reliability. Distribution component failures are mitigated through various capital and infrastructure improvement processes. Infrastructure upgrade and replacement activities consider severity of operating deficiencies, load growth, local system topology, infrastructure age and condition, available new equipment and technologies, and local loading characteristics.

Commencing July 2011, NIPSCO has experienced good customer interest and participation in the introduction of customer-owned renewable resource-based generation onto its electric distribution system. Renewable generation projects, for the most part, effectively began coming on line in 2012. New projects were interconnected throughout 2013 and are continuing to be built in 2014. Recent customer generation additions are a result of NIPSCO's Net Metering and FIT generation interconnection programs. These relatively new programs were developed and made available to customers to provide an incentive and path for customers to integrate their own distributed generation resources into NIPSCO's distribution and sub-transmission level networks. Solar, wind, and biomass fueled generation resources have been deployed by customers in varying amounts.

More specifically, Net Metering is an electricity policy for consumers who own renewable energy facilities (i.e., PV solar, wind, biomass, and hydro). It is used as an incentive for customers to install renewable energy systems by reimbursing them for their generation output, at NIPSCO retail rates, for energy in excess of their service's base load electricity purchase from the utility. Typically this represents the excess power produced that is not utilized internally by the customer but is instead delivered into the utility's local electric system. The program covers customer generation installations that are rated up to one MW in size. Current individual generation installations range in size from 2 kW to 900 kW.

As of December 31, 2013, 38 MW of output capacity was operational and interconnected to NIPSCO's electric systems. An aggregate breakdown by renewable fuel type is provided below. These values represent installed generation resources including landfill gas combustion engines, animal waste gas combustion engines, larger commercial PV solar array farms, small roof mounted and ground mounted residential solar arrays, intermediate-sized commercial wind turbines, and small commercial and residential wind turbines.

- 15.50 MW - PV solar generation
- 1.98 MW - Wind-powered generation
- 21.06 MW – Biomass-fueled generation

Currently identified new customer-owned renewable generation projects that are planned to be placed in service in 2014 are represented through the following fuel resource type breakdown.

- 0.19 MW - PV (photovoltaic) solar generation
- 0.11 MW - Wind-powered generation
- 10.85 MW - Biomass-fueled generation

It should be noted that the above biomass fuel generation totals include 13.6 MW of existing and 4 MW of 2014 scheduled landfill-based generation interconnected to NIPSCO systems. Although this renewable generation is interconnected to NIPSCO, their output power deliveries are associated with customer purchase power agreements with parties other than NIPSCO, and do not participate in the current net meter or FIT programs.

Distribution Planning has observed various impacts on system operating characteristics due to activities associated with customer-owned generation. These impacts are primarily related to the new net metering and FIT pilot programs, which became effective in the last few years. The full extent of impacts on system operations and demand has yet to be determined and will depend upon the demonstrated long term performance and reliability of various installed generating resources including solar-, wind-, and biomass-based generation fueled resources. Differences in operational characteristics, power delivery timing, and location all affect the relative impact on local distribution system operations at any given time. The diverse types of customer-owned generation have varying effects on the electric system.

Initially, it has been observed that local generation can vary substantially depending upon individual customer equipment and generation input resources. Fuel resource type affects power delivery in various ways depending upon owner-controlled resources as in the case of landfill and animal by-product gas inputs, or external environmental conditions such as wind velocity and solar irradiance. Highly variable outputs have been observed to occur on solar PV installations. Rapid changes in solar generation have exhibited swings of 85 percent of full rated output, within a 60-second time period. These conditions represent sizable down-up-down shifts in system operating characteristic on local circuits associated with some of the larger half megawatt or greater rated customer-owned solar fields. These swings can present challenges to maintaining good service voltage stability on distribution circuits.

In addition to these more rapid changes relating to the recognized cloud affect, it has also been observed that more widespread weather patterns such as seasonal rain or snow storms can also dramatically influence individual daily peak PV generation outputs. Longer duration output reductions of 75 to 92 percent of rated equipment output were not uncommon during inclement weather conditions. Smaller distribution system wind- powered generation was also observed to be as much if not more unpredictable and variable in power delivered to the distribution system. On the other hand, large biomass-fueled combustion turbines appear to be less volatile in generated outputs as compared to solar- and wind-associated generation. Landfill- based biomass generation facilities tended to be more predictable followed by animal waste gas associated generation. However, it is worth noting that even though biomass-fueled resources exhibited a steadier dispatch of power, there were experiences of random events where customer generation drops off line. This type of drop-off impact becomes more significant with the multi-megawatt level of many biomass facilities.

Based on recent observations of currently installed renewable generation resources, these technologies present a recognized energy source that can be utilized in supporting customer load. Their impact on local electric infrastructure, however, has not demonstrated to be sufficiently predictable or stable enough to be considered a substitute for NIPSCO's local electric system distribution infrastructure in reliably meeting the local electric capacity and service needs of customers on a 24/7 basis. Continued traditional capital investment into local distribution infrastructure improvements and upgrades will continue to be needed to adequately meet utility service obligations.

Distribution Automation ("DA") is defined as the coordinated, automatic control of substation breakers and interrupting-type line switches within an electric distribution system, along with the centralized retrieval of associated operating data for control and monitoring purposes.

NIPSCO's distribution automation system enables control and automatic isolation of electric distribution line faults and the restoration of services during various 12.5 kV circuit outage conditions. This action is accomplished through independent sectionalizing of specific circuits through the use of automatic line switches and computer-controlled substation breakers. Built-in algorithms are utilized to analyze operating conditions such as line and substation loading, to determine best response to system disturbances. Automatic restoration increases distribution system reliability by reducing the number of customers experiencing a sustained outage. Besides the advantage of quick restoration of electric service, real-time operating data can also be retrieved and stored on electric management system. DA Systems provide timely and accurate outage-related information to restoration teams, speeding up problem identification. This action supports quicker overall response time to identify system problems and develop repair procedures. These factors result in further improvements in customer service and system reliability. An added benefit of real-time data retrieval and device remote control is the more effective use of labor resources for operation and maintenance of the electric distribution system.

NIPSCO currently utilizes distribution automation equipment on 27 percent of its distribution substations and 23 percent of its total distribution circuit population. All new and rebuilt distribution substations and associated circuits continue to be equipped with new distribution automation as infrastructure is replaced. As part of annual capital investment programs, new and/or rebuilt substation projects are being implemented at a rate of one to two distribution stations per year.

As part of the long-term view, NIPSCO continues to evaluate the benefits of smart grid and DA technology. NIPSCO will assess deployment of smart grid technology based upon development of reasonable business cases.

SECTION 11

2014 Integrated Resource Plan

In This Section

A Short-Term Action Plan identifies the steps the Company will take during 2014 through 2016 to implement the strategic plan. The plan provides for compliance with applicable mandates and policies, and uses a balanced approach to manage cost, risk, uncertainty and reliability elements. The long-term strategic plan identifies customer and resource needs over a twenty-year planning horizon, and recommends a potential resource portfolio to reliably and cost-effectively meet customers' future needs. In the following paragraphs, NIPSCO discusses the Short-Term Action Plan and Long-Term plan.

- *The long-term plan identified capacity needs to cover reserve margin starting in 2020; NIPSCO may be able to meet its projected capacity needs with additional interruptible service and when needed, will purchase capacity until 2023, when NIPSCO anticipates the need for a CCGT. Another CCGT may be needed in 2035.*
- *NIPSCO continues to monitor variables that contribute to uncertainties and impact the resource plan*
- *In NIPSCO's Short-Term Action Plan for the years 2014 through 2016, NIPSCO will:*
  - *Continue to utilize existing resources, including interruptible resources as needed to meet its requirements.*
  - *Explore the potential for increased interruptible (R675 Option D) resources.*
  - *Implement approved DSM programs for 2015 and seek approval for DSM programs to be offered in years 2016 and 2017.*
  - *Implement the approved FIT.*
  - *Continue to comply with standards and regulations, including environmental regulations by investing in compliance projects, and develop compliance strategies for new regulations as they are finalized.*
  - *Develop a distributed generation strategy.*
  - *Continue to implement infrastructure modernization plans.*
- *NIPSCO's long-term planning process looks for safe, reliable, low-cost solutions to meet customers' future energy needs.*

Short-Term Action Plan

The Short-Term Action Plan identifies the steps the NIPSCO will take during 2014 through 2016 to implement NIPSCO's long-term resource plan. In those years, NIPSCO will utilize available interruptible resources as needed to meet its requirements. NIPSCO will also continue to:

- Invest in infrastructure modernization to maintain safe and reliable delivery of energy services
- Explore the potential for increased interruptible (R675 Option D) resources
- Offer service options for customers, including demand-side management
- Comply with NERC Critical Infrastructure Protection ("CIP") cyber security standards
- Comply with new regulations, including EPA regulations
- Develop a distributed generation strategy
- Implement revisions to the FIT

NIPSCO will continue to monitor changes in business conditions and technologies that may affect the plan. NIPSCO will seek approvals as appropriate to implement the short-term plan.

Long-Term Plan

NIPSCO evaluated resource options to determine the combinations of supply-side, demand-side, self-build and market resources to meet its capacity needs. NIPSCO performed sensitivity analyses for different economic, environmental, cost, risk, and regulatory uncertainty. The optimal plan was identified. The plan identified that additional capacity purchases are needed beginning in 2020 to cover reserve margin. NIPSCO may be able to meet its projected capacity needs with additional interruptible service. If such resources are not available, NIPSCO will supplement its capacity needs through the proposed MISO Capacity Auction or bi-lateral contracts. The capacity needs for the period of 2020 through 2022 do not exceed 50 MW. In 2023, NIPSCO anticipates the need for a CCGT or intermediate type resource and in 2035. The CCGT purchases are consistent with the results of the State Utility Forecasting Group ("SUFG") forecast date December 2013. Figure 11-1 below shows the resources added and potential unit retirements for the period 2014 - 2035. Similar to the 2011 IRP, the plan reflects increased energy efficiency and demand-side management resources, increased market purchases, similar CCGT additions and potential coal-fired generation retirements.

Figure 11-1
NIPSCO's Long-Term Plan

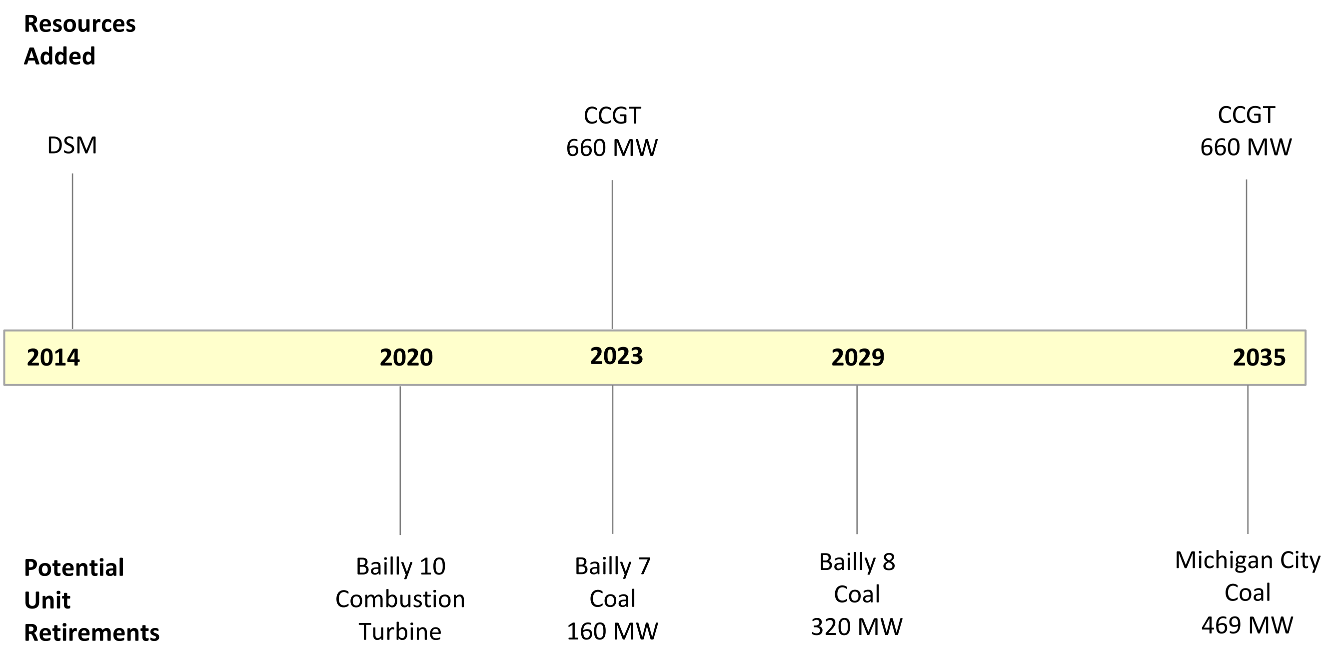


Table 11-1 summarizes the capacity position with the identified plan.

Table 11-1
Assessment of Existing and Future Resources vs. Demand Forecast (BDSM)

	(a)	(b)	(c)	(d)	(e)	
Year	**Unforced Capacity - UCAP (MW)**	**Internal Peak - FP0714c (MW)**	**Demand Response (MW)**	**Internal Peak Minus Demand Response (MW)**	**Internal Peak Minus Demand Response Plus Reserve Margin (MW)**	**Capacity Position Long/(Short) (MW)**
				(b)-(c)	(d) + (d) x Reserve Margin	(a)-(e)
2014	3,130	3,208	377	2,830	3,037	124
2015	3,143	3,212	377	2,835	3,042	101
2016	3,143	3,219	377	2,842	3,050	93
2017	3,143	3,235	377	2,858	3,066	77
2018	3,143	3,253	377	2,876	3,086	58
2019	3,143	3,273	377	2,896	3,108	36
2020	3,123	3,291	377	2,914	3,127	(4)
2021	3,123	3,311	377	2,934	3,148	(24)
2022	3,123	3,332	377	2,955	3,171	(47)
2023	3,646	3,352	377	2,975	3,192	453
2024	3,640	3,372	377	2,995	3,213	426
2025	3,640	3,391	377	3,014	3,234	405
2026	3,637	3,410	377	3,033	3,255	383
2027	3,637	3,429	377	3,052	3,275	362
2028	3,637	3,447	377	3,070	3,294	343
2029	3,330	3,465	377	3,088	3,314	16
2030	3,330	3,483	377	3,106	3,333	(3)
2031	3,327	3,497	377	3,120	3,347	(20)
2032	3,327	3,511	377	3,134	3,363	(36)
2033	3,327	3,542	377	3,165	3,396	(69)
2034	3,327	3,558	377	3,181	3,413	(86)
2035	3,554	3,574	377	3,197	3,430	124

NOTES:
1. UCAP is a NIPSCO estimated value
2. UCAP reflects units retiring after the peak season in the years 2019, 2022, 2028 and 2034
3. Reserve Margin for 2014-2035 is 7.3 percent.

As part of the long-term plan, NIPSCO will also continue to:

- Invest in infrastructure modernization to maintain safe and reliable delivery of energy services
- Comply with NERC CIP cyber security standards
- Offer service options for customers, including demand-side management
- Comply with new regulations, including EPA regulations

NIPSCO determined the types of resources that would need to be acquired to serve customers during the twenty-year study period through its planning process. This plan is based upon the most current information available. NIPSCO will seek regulatory approval to bring new resources into its portfolio as appropriate. In the short-term, it was determined that existing resources could sufficiently meet customers' needs. However, when a need is identified, NIPSCO will evaluate financing options for resource acquisitions.

Given the numerous variables that contribute to uncertainty in NIPSCO's 2014 IRP, results are subject to change based on updated information. NIPSCO will continue to evaluate its resource plan as necessary. The IRP is part of NIPSCO's ongoing business process; new information is processed as it becomes available. The plan is forward-looking and organic.

List of Acronyms

APWR	Advanced Pressure Water Reactor
BART	Best Available Retrofit Technology
BATC	Batteries Commercially Available
BATE	Batteries Emerging Technologies
BIOR	Biomass Reciprocating Engine
BIOS	Biomass Stoker Boiler
CAA	Clean Air Act
CAES	Compressed Air Energy Storage
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAPs	Community Advisory Panels
CATR	Clean Air Transport Rule
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Days
CFL	Compact Fluorescent Lighting
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CPI	Consumer Price Index
CPP	EPA Draft Clean Power Plan
CPS	Clean Energy Portfolio Standard
CPV	Concentrated Solar Power
CSAPR	Cross-State Air Pollution Rule
CSR	Customer Service Representative
CT	Combustion Turbine
CTA	Aeroderivative Combustion Turbine
CTF	Frame Combustion Turbine
CC and CCGT	Combined Cycle Combustion Turbine
CONV	Two Frame Combustion Turbines converted to a CCGT
CWA	Clean Water Act
DFGD	Dry Flue Gas Desulfurization
DLC	Direct Load Control
DLN	Dry Low NO_x
DRR	Demand Response Resource
DSM	Demand-Side Management
EDR	Economic Development Rider
EEMS	Emission-Economic Modeling System
EGU	Electric Generating Unit
EIA	Energy Information Agency
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FC	Fuel Cells
FIT	Feed in Tariff
FGD	Flue Gas Desulfurization
GEO	Geothermal
GHG	Green House Gases
GWh	Gigawatt hours
HAP	Hazardous Air Pollutant
HCI	Hydrogen Chloride
HDD	Heating Degree Days
Hg	Mercury

ICR	Information Collection Request
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission
IVR	Interactive Voice Response
kW	Kilowatts
kWh	Kilowatt hours
LAES	Liquefied Air Energy Storage
LMP	Locational Marginal Price
LNB	Low NO_X Burners
MACT	Maximum Achievable Control Technology
MAE	Mean Absolute Error
MISO	Midwest Independent Transmission System Operator, Inc.
MPCP	Multi-Pollutant Compliance Plan
MT	Microturbines
MTEP	MISO Transmission Expansion Plan
MW	Megawatts
MWh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NDC	Net Demonstrated Capability
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NIPSCO	Northern Indiana Public Service Company
NOAA	National Oceanic and Atmospheric Administration
NODA	Notice of Data Availability
NO_x	Nitrogen Oxide or Oxides of Nitrogen
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirements
O&M	Operating and Maintenance
OFA	Over-Fire Air
PC	Pulverized Coal
PJM	PJM Interconnection LLC
PM	Particulate Matter
PPA	Purchased Power Agreement
PRB	Powder River Basin
PSH	Pumped Storage Hydro
PV	Solar Photovoltaic
RCRA	Resource Conservation and Recovery Act
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SMR	Small Modular Reactor
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
TOA	Transmission Owners Agreement
TPA	Third Party Administrator
UCAP	Unforced Capacity
WFGD	Wet Flue Gas Desulfurization
WNOF	Off-Shore Wind
WNON	On-Shore Wind

Definitions

Allowance - the authorization by the EPA/IDEM under a promulgated emissions trading program to emit up to one unit of pollutant during or after a specified calendar year or control period. Regulations for emission trading programs are currently in place or under development in Indiana for SO_2, NO_x (annual and ozone season) and Hg.

Avoided Cost - the cost of fuel, operation, maintenance, purchased power, labor, capital, taxes, and other costs not incurred by a utility if an alternative supply or demand-side resource is included in the utility's IRP.

Clean Air Act Amendments of 1990 ("CAA") - Title IV, Acid Deposition Control, of the federal Clean Air Act Amendments of 1990, 42 U.S.C. 7401 to 42 U.S.C. 7671(q), in effect November 15, 1990.

Cogeneration Facility - 1) a facility that simultaneously generates electricity and useful thermal energy and meets the energy efficiency standards established for a cogeneration facility by the FERC under 16 U.S.C. 824a-3, in effect November 9, 1978; 2) the land, system, building, or improvement that is located at the project site and is necessary or convenient to the construction, completion, or operation of the facility; 3) the transmission or distribution facility necessary to conduct the energy produced by the facility to a user located at or near the project site.

Conservation - the amount of energy saved by a customer for a specific end-use.
Conservation includes behavior changes such as thermostat setback. Conservation does not include changing the timing of energy use, switching to another fossil fuel source, or increasing off-peak usage.

Cooling Degree Day ("CDD") – A form of Degree Day used to estimate energy requirements for air conditioning or refrigeration. Typically, CDD are calculated on how much warmer the mean temperature at a location is than 65 degrees F on a given day. For example, if a location experiences a mean temperature of 75 degrees F on a certain day, there were 10 CDD that day because 75 - 65 = 10.

Demand-Side Management ("DSM") - the planning, implementation, and monitoring of a utility activity designed to influence customer use of electricity that produces a desired change in a utility's load shape. DSM includes only an activity that involves deliberate intervention by a utility to alter load shape.

Demand-Side Resource - a resource that reduces the demand for electrical power or energy by applying a demand-side program to implement one or more demand-side measures.

Demand Response – programs designed to encourage customers to modify the timing and level of electricity demand from their normal consumption patterns in response to:

a. changes in the price of electricity over time, or
b. incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Discount Rate - the interest rate used in determining the present value of future cash flows.

End-Use - the light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process or other useful work produced by equipment using electricity.

Energy Efficiency - reduced energy use for a comparable level of energy service.

Energy Service - the light, heat, motor drive or other service for which a customer purchases electricity from a utility.

Engineering Estimate - an estimate of energy (kWh) and demand (kW) impact resulting from a demand-side measure based on an engineering calculation procedure. An engineering estimate addresses change in energy use of a building or system resulting from installation of a DSM measure. If multiple DSM measures are installed, an engineering estimate accounts for the interactive effect between the DSM measures.

Heating Degree Days ("HDD") – a form of degree day used to estimate energy requirements for heating. Typically, HDD are calculated as how much colder the mean temperature at a location is than 65 degrees F on a given day. For example, if a location experiences a mean temperature of 55 degrees F on a certain day, there were 10 HDD that day, because 65 – 55 = 10.

Integrated Resource Plan ("IRP") - a utility's assessment of a variety of demand-side and supply-side resources to cost-effectively meet customer electricity service needs. The IRP usually includes an analysis of the uncertainty and risk posed by different resources and external factors.

Load Shape - the time pattern of customer electricity use and the relationship of the level of energy use to a specific time during the day, month, and year.

Major Industrial - transmission voltage customers (22 in 2009) who account for more than 70 percent of the NIPSCO industrial segment energy consumption, about 40 percent of system energy sales and 30 percent of internal peak hour demand. The NIPSCO Major Accounts - Transmission department surveys these customers and discusses the outlook for their business before providing input to NIPSCO's forecast.

Participant - a utility customer participating in a utility-sponsored DSM program.

Participant Test - a cost-effectiveness test that measures the difference between the cost incurred by a participant in a demand-side program and the value received by the participant. A participant's cost includes all costs borne by the participant. A participant's value from a DSM program consists of only the direct economic benefit received by the participant.

Penetration - the ratio of the number of a specific type of new program units installed during a given time period to the total number of new program units installed over the program's total implementation time period.

Planning Reserve Margin – additional resources required above those needed to directly serve the load required to cover operating reserves, load forecast errors, and scheduled and forced outages.

Present Value - today's value of a future payment, or stream of payments, discounted at some appropriate compound interest or discount rate.

Program Cost - all expenses incurred by a utility in a given year for operation of a DSM program whether the cost is capitalized or expensed. An expense includes, but is not limited to, the following:

1. Administration.
2. Equipment.
3. Incentives paid to program participants.
4. Marketing and advertising.
5. Monitoring and evaluation.

Ratepayer Impact Measure ("RIM") Test - a cost-effectiveness test that analyzes how a rate for electricity is altered by implementing a DSM program. This test measures the change in a revenue requirement expressed on a per-unit of sale basis.

Renewable Resource - a generation facility or technology utilizing a fuel source such as, but not limited to, the following: wind; solar; geothermal; waste; biomass; and, small hydro.

Resource - a facility, project, contract, or other mechanism used by a utility to provide electric energy service to the customer.

Saturation - the ratio of the number of a specific type of similar appliance or equipment used to serve a particular end-use to the total number of customers in that class or the total number of similar appliances or equipment serving that end-use.

Screening - an evaluation performed by a utility to determine whether a demand-side or supply-side resource option is eligible for potential inclusion in the utility's IRP.

Short-Term Action Plan - a schedule of activities and goals developed by a utility to begin efficient implementation of its IRP. For the purposes of this IRP, Short-Term is defined as the period 2014-2016.

Standard Industrial Classification ("SIC") - a system developed by the United States Department of Commerce for use in the classification of establishments by type of activity in which engaged, for purposes of facilitating the collection, tabulation, presentation and analysis of data relating to establishments, and for promoting uniformity and comparability in the presentation of statistical data collected by various agencies of the United States government, state agencies, trade associations, and private research organizations.

Supply-Side Resource - a resource that provides a supply of electrical energy or capacity, or both, to a utility. A supply-side resource includes the following:

1. A utility-owned generation capacity addition.
2. A wholesale power purchase from another utility or non-utility generator.
3. A refurbishment or upgrading of an existing utility-owned generating facility.
4. A cogeneration facility.
5. A renewable resource technology.

Total Resource Cost ("TRC") Test - a cost-effectiveness test that eliminates the distinction between a participant and non-participant by analyzing whether a resource is cost-effective based on the total cost and benefit of the program, independent of the precise allocation to a shareholder, ratepayer, and participant.

Utility Cost Test - a cost-effectiveness test designed to minimize the net present value of a utility's revenue requirements. Also known as a revenue requirements test.

Index by Commission Rule 170 IAC 4-7

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	(b)	1	Preferred resource portfolio - description	Sec 9-Scenarios and Sensitivities Analysis Sec 11-NIPSCO's Long-Term Plan
		2	Preferred resource portfolio - variables, assumptions affecting the portfolio	Sec 1-Business Climate
		3	Supply and demand side resource options evaluated consistent and comparable basis	Sec 7 CONFIDENTIAL Appendix I, K
		4	Preferred resource portfolio utilizes load mgmt , DSM, renewable, cogeneration, distributed generation,	Sec 9- Plan Development
		5	DSM impact, if any, on transmission and distribution system	Sec 5-2016-2035 DSM Resources
		6	Preferred resource portfolio - finance impact of acquiring future resources	CONFIDENTIAL Appendix I, K
		6-a	Preferred resource portfolio - operating & capital costs	CONFIDENTIAL Appendix I, K
		6-b	Preferred resource portfolio - average cost per kilowatt	CONFIDENTIAL Appendix I, K
		6-c	Preferred resource portfolio - avoided cost for each year	Sec 9-Table 9-11
		6-d	Preferred resource portfolio - ability to finance portfolio	Sec 11-NIPSCO's Long-Term Plan
		7	Preferred resource portfolio - balances cost with risk	Sec 9-Sensitivities and Scenarios
		7-a	Preferred resource portfolio - identification and explanation of assumptions	Sec 9-Integration Analysis Assumptions
		7-b	Preferred resource portfolio - assumed risks and uncertainties	Sec 1 Sec 9-Sensitivities and Scenarios

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		7-c	Preferred resource portfolio - portfolio performance across wide range of futures	Sec 9-Sensitivities and Scenarios
		7-d	Preferred resource portfolio – NPVRR and risk metric results of portfolio testing, ranking, portfolios, $/kWh, discount rate	Sec 9-Table 9-11
		7-e	Preferred resource portfolio - assessment how robustness	Sec 9
		8	Preferred resource portfolio - workable strategy for reacting to unexpected changes	Sec 9-Sensitivities and Scenarios
		8-a	Preferred resource portfolio adaptability to unexpected changes to demand for electric service	Sec 9-Sensitivities and Scenarios
		8-b	Preferred resource portfolio adaptability to unexpected changes to cost of new resources	Sec 9-Sensitivities and Scenarios
		8-c	Preferred resource portfolio adaptability to unexpected changes to regulatory compliance	Sec 9-Sensitivities and Scenarios
		8-d	Preferred resource portfolio adaptability to unexpected changes to factors affecting the forecasted relationship of supply/demand for electric service to be in error	Sec 9-Sensitivities and Scenarios
Section 9			**Short Term Action Plan**	
	1	A	Resources and objective of the preferred resource portfolio	Overview
		B	Criteria for measuring progress toward objective	Sec 11-Short-Term Plan
	2		Implementation schedule	Sec 11
	3		Resource/program budget with an estimated range	Sec 5-2016-2035 DSM Resources Sec 10-NIPSCO Transmission System Capital Projects CONFIDENTIAL Appendix J
	4		Difference between 2011 and 2014 IRPs	Sec 11