

**ASSESSMENT OF OTHER FACTORS:  
BENEFIT-COST ANALYSIS OF TRANSMISSION EXPANSION PLANS**

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## **ASSESSMENT OF OTHER FACTORS: BENEFIT-COST ANALYSIS OF TRANSMISSION EXPANSION PLANS**

American Transmission Company (“ATC”) has engaged Christensen Associates Energy Consulting, LLC (CA Energy Consulting) to assist in the assessment of the benefits and costs of proposed transmission projects of the Access Study Initiative (“ASI”). ATC’s ASI was launched in 2004 in response to input from stakeholders, emerging regional energy markets, and the desire of market participants for improved and less costly access to resources within the region. As a result, key project options to improve transfer capability of the ATC grid and to increase transmission system access for ATC’s customers, including retail service providers and other stakeholders, are identified and evaluated. The ASI has been undertaken in conjunction with and in addition to regular ATC public planning process activities, as reviewed in ATC’s *10-Year Transmission System Assessment* (hereafter referred to as “TYA”) reports issued every six months.

The ASI considers monetized benefits and costs arising from energy cost savings from transmission investment, based on simulations of the operation of the transmission system with and without the ASI projects performed by ATC. “Other Factors” were also considered by ATC in its initial project evaluations.

This report presents a methodology for assessing the Other Factors that affect the benefits and costs that are likely to accompany implementation of the following five candidate expansion plans of ATC’s ASI:

- Paddock to Rockdale (“Paddock”)
- Salem to North Madison (“Salem”)
- Lower-Voltage Reinforcements (“Lower-Voltage”)
- Byron to North Madison (“Byron”)
- Prairie Island to Columbia (“Prairie”)

The methodology provides the Public Service Commission of Wisconsin (“PSCW”), stakeholders to the ATC planning process, and ATC with a general guide for explicit incorporation of these Other Factors into the overall evaluation of transmission expansion options. The Other Factors that we consider include those identified by the participants and stakeholders to ATC’s Access Initiative process, including ATC. The quantitative analysis of the Other Factors draws upon the information that is available currently. As a consequence of data and information limitations, however, the empirical analyses contained herein often depart from the technical methodology as proposed. Nonetheless, the analysis of Other Factors of the project options provides a reasonable initial assessment. This assessment, as presented in this report, can and should be used to guide general decisions at this time.

In this report, for each of the Other Factors, we compare the five candidate transmission enhancement projects with a Base Case. Each of the five projects is distinguished from the Base Case by changes to the topology of ATC’s transmission system in 2013, the year selected for assessment of impacts.

The first section describes the general approach taken with respect to quantitatively or qualitatively assessing the additional benefits and costs of these five projects. Unbundled wholesale electricity markets are unusually complicated, and Section 1 pays particular attention to the inherent limitations of modeling for purposes of the assessment of the benefits of transmission expansion options. The subsequent six sections then assess the Other Factors, which we assign to the following six categories:

- Reduced Operating Risks
- Reliability Benefits
- Power System Externalities
- Environmental Benefits and Costs
- Benefits Related to Economic Development
- Fairness and Equity Aspects

Each of these six sections describes the factors within the category, explains how they might be best assessed, and identifies major data and information inputs necessary to perform a comprehensive analysis. Where possible, the report presents initial analysis results for the Other Factors. Two factors, Operating Flexibility and Environmental Externalities, cannot be quantified at this time because of limitations of data and information.

The final section of this report integrates the quantitative and qualitative analyses and summarizes the results for each of the candidate expansion options. The Appendix includes a listing of background data and a review of consumer outage cost studies, which were either implicitly incorporated or explicitly utilized in the immediate study.

## **1. OVERVIEW OF METHODOLOGY**

Transmission projects give rise to both direct and indirect benefit and cost flows of several dimensions.<sup>1</sup> Ideally, the full gamut of benefits and costs including the Other Factors would be valued in money terms and then incorporated directly within the main analytical framework. However, because of limitations in data, analytical tools, and resources, it is not always cost-effective, practical, or possible to monetize all of the Other Factors associated with transmission plans. Nonetheless, it is appropriate to capture to the extent possible all dimensions of Other Factors, even where such impacts cannot be readily monetized. The assessment of the transmission expansion plans should incorporate the Other Factors in their various dimensions as non-monetized quantitative or qualitative factors.

ATC utilizes the PROMOD IV production cost simulation model to quantify the monetary values of the production cost savings that can be derived from various transmission expansion options.<sup>2</sup> Benefits of the project options include reductions in generation production costs and

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<sup>1</sup> “Direct” effects are impacts that occur within electricity markets, while “indirect” effects are impacts that occur outside electricity markets.

<sup>2</sup> PROMOD IV is a production simulation model that estimates hourly generation costs, power flows, and nodal LMPs. It considers generating unit operating characteristics and transmission constraints. It is a product of New Energy Associates, a subsidiary of Siemens Company. PROMOD IV minimizes total generation running costs subject to several constraints: supply and demand must be in balance; each generator must operate within its

reduced transmission line losses. The results of these analyses are contained in the companion report prepared by ATC.<sup>3</sup>

### 1.1. Assessment Using Multi-Criteria Analysis

A practical approach to assessing the Other Factors is to employ *Multi-Criteria Analysis (MCA)*. This approach involves the construction of quantity metrics that can be converted into measures of worth or merit. The quantity metrics will vary according to the definition of each Other Factor. The key task is to define metrics that reasonably represent the underlying benefit flows, which typically are unobserved. The specific metrics along with their conversions to merit scores are described in Sections 2 through 7 of this report.

Multi-Criteria Analysis includes a body of techniques that enable decision makers to formally evaluate and possibly quantify factors that cannot otherwise be monetized.<sup>4</sup>

The MCA approach makes the assessment of Other Factors explicit, although its application unavoidably involves an exercise of well-informed judgment. The advantage of formal MCA techniques is that they provide an explicit relative weighting system for evaluating the Other Factors. The main role of MCA techniques is to provide viable means for managing large amounts of complex information in a consistent way. MCA techniques can be used to identify a single most preferred project, to rank projects, to short-list a limited number of projects for subsequent detailed appraisal, or simply to distinguish acceptable from unacceptable alternatives.

The MCA approach brings structure and transparency to judgment of how projects compare regarding factors that are not directly or easily monetized. It consists of comparative assessments, both quantitative and qualitative, of how well each project option satisfies predefined objectives as reflected in the Other Factors. Some of the Other Factors, by their very definition, can serve directly as the relevant criteria (or objectives) for the quantitative assessment using MCA; but in other cases, a set of more refined criteria may need to be developed by which a qualitative assessment can be conducted.

In the simplest cases, project assessment can consist of a qualitative description or mere confirmation that a project satisfies a particular constraint or objective. In larger or more complex cases, project assessment can consist of measurement of impacts in suitable non-monetary units, or the use of relative weights for each criterion, which then allows explicit scoring or ranking of each project.

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operating limits; and transmission flows must be equal to or below line flow limits. The software determines network solutions which include MWs of output of individual generators, locational power prices (LMPs), and flows on flowgates – for each analysis timeframe.

<sup>3</sup>American Transmission Company [2005].

<sup>4</sup> An extensive body of literature has emerged over the past twenty years addressing the issues associated with complex decision making involving multiple objectives and options, where the factors cannot be readily quantified or monetized. Two important contributions to the literature of strategic decision analysis (SDA) are Keeney and Raiffa [1976] and Olson [1995]. Additional literature on multi-criteria analysis (MCA), which is embodied in SDA, includes Bana e Costa *et al.* [1999], Bana e Costa and Vansnick [1997], Bazerman [1998], Brownlow and Watson [1987], Clemen [1996], Hammond, Keeney, and Raiffa [1999], Keeney [1987, 1992], Keeney and von Winterfeldt [1988], Merkhofer and Keeney [1987], and Yoon and Hwang [1995].

A standard feature of MCA is a *decision matrix*, in which each column pertains to a particular project and each row measures the performance or impact of the project against each performance criterion. The individual performance assessments are often numerical, but may also be expressed as qualitative scores.

Combining the performance matrix with the scoring approach, the expected impacts of each transmission project are assigned a numerical score for each of the Other Factors on a “strength of preference scale.” More preferred project impacts score higher on the scale, and less preferred project impacts score lower. For simplicity, we use a 0 to 10 scale to score transmission projects, where 0 represents the “least preferred” impact while 10 represents the “most preferred” impact. Once scores for each Other Factor for each transmission project have been determined, numerical weights can be assigned to determine the relative valuations of the various Other Factors.

If weights are applied, the choice of a weight to apply to a specific factor should reflect: a) the *range* of the differences of the projects’ scores for that factor; b) how much the different scores for that factor matter to the selection of optimal (best) projects; and c) informational quality, so that factors based upon less accurate information may be awarded relatively lower weights vis-à-vis other categories. It is possible, for example, that a factor that is viewed as “very important” (e.g., reliability or economic development) could be awarded a lower weight than a factor viewed as relatively less important, (e.g., societal impacts) if the differences in the scores for the very important factor are small, making it difficult to distinguish among projects, or if information quality is not of a high level.

Often, weights will be derived from the preferences of stakeholders. Weights can be developed from surveys or through meetings with key stakeholders. The process could obtain weight sets for each stakeholder. The sets could then be compared, with an opportunity for reflection and change followed by an attempt to reach consensus. If no consensus can be reached, it might be best to take two or more sets of weights forward in parallel, for agreement on a choice of projects can sometimes be achieved even without agreement on the weight set. Even if this does not lead to agreement, explicit awareness of the different weight sets and their consequences can facilitate the search for compromise.

In summary, an MCA process may include the following elements:

1. Determine the objectives of the MCA.
2. Identify the decision makers and other key players.
3. Define the project options to be assessed.
4. Identify the objectives (attributes defined in terms of a metric) and merit scoring approach. In the context of Access Initiative, the defined objectives are the Other Factors. The performance of a project according to the objective (Other Factor) should reflect the benefit or cost impacts that may result from the implementation of each project.
5. Describe, measure, or assess the expected performance of each project according to the identified objective (Other Factor). If the analysis is to include steps 6 and 7 below, then score each project according to the objectives.
6. Assign weights to the Other Factors to reflect their relative importance.

7. Compute a weighted score for each project to derive an overall project value.
8. Conduct a sensitivity analysis of the results to changes in weights (and possibly scores).

The MCA approach taken in this report includes the following major elements:

*Impact assessment:* First, determine the performance of the transmission projects for the defined metric for each of the Other Factors. For each project, merit scores are assigned to the project’s performance, based on the project’s achieving or satisfying the objectives.

*A decision matrix.* The resulting merit scores of the AIS project options are summarized in a decision matrix.

One limitation of MCA methods is that they cannot show that, in total, a transmission expansion option explicitly adds to or detracts from overall social welfare. Unlike traditional economic benefit-cost analysis, there is no explicit rationale or necessity for a rule that states that benefits should exceed costs. Thus, as is often the case with cost-effectiveness analysis, the “best” project according to MCA may not necessarily maximize social welfare.

## 1.2. Assumptions and Scenarios

*Load and Energy:* Table 1 shows annual class loads for 2013. The figures are derived according to procedures that are described in the Appendix.

**Table 1**  
**Electricity Consumption by Class for 2013 (GWh)**

Class	Load
Residential	24,634
Commercial	24,858
Industrial	32,118
Total	81,610

*Generation:* Generation projects in progress or planned as of the end of 2004 were included in the analysis of the Base Case and the five projects, if all of the following conditions were satisfied:

- Interconnection studies were completed (i.e., stability and short circuit studies),
- Facilities required for interconnection were determined,
- Deliverability studies were completed,
- Facilities required for delivery were determined, and
- The entity requesting delivery accepted the terms of the delivery service.

The listed projects can be found in the TYA and in the companion ATC report.<sup>5</sup> Altogether, the 2013 Base Case analyses include 3,732 MW of additions in generating capacity within the ATC service territory, and retirements of 358 MW realized during the 2003-2005 timeframe.<sup>6</sup>

Our analyses, wherever possible, also takes account of sensitivity studies performed by ATC that provide a basis to assess, where appropriate, risks regarding key dimensions of benefits and costs. ATC has quantified outcomes for different cases using PROMOD IV, including production costs, locational marginal prices (LMPs), imports to and exports from Wisconsin, and physical transfers. These cases provide a basis for gauging increased optionality obtained by the Access Initiative expansion projects for the major service providers and other market participants within the ATC footprint. The PROMOD sensitivity cases are performed for the 2013 analysis year and include, among others, the following analyses:

- High gas prices (20% increase in fuel cost relative to the Base Case) for all gas and oil generator units;
- \$50 adder to the supply offers by combustion turbine generators operating within the ATC footprint;<sup>7</sup>
- Three nuclear units simultaneously out of service in the ATC footprint;
- Elm Road Phase III in-service; and
- Generator offers in ATC footprint equal to 150% of marginal running costs.<sup>8</sup>

### 1.3. Limits of Modeling

Quantifying the multi-dimensional benefits and costs associated with the Access Initiative project is challenging. Several aspects of the evaluation are worthy of consideration.

First, transmission facilities provide benefits over long periods of time. Consequently, the magnitude of the benefits of any transmission expansion project is highly dependent upon future conditions. As a result, the assessment of expansion plans involves, to the degree possible, the quantification of uncertainty over future states of regional power systems and markets over extended timeframes. The informational and data limitations that ATC faces with regard to the state of the world within its service territory and in neighboring regions in 2013 and beyond naturally limits the degree of precision with which ATC can project benefits and costs of these projects. This is a general concern in any analysis of this kind.

Second, assessments of transmission plans are confounded by the inherent uncertainties in the pattern of future electricity demand; the future pattern of regional power transfers; the availability of generation facilities; the availability of the various components of the transmission

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<sup>5</sup> American Transmission Company [2005a, pp. 8-10] and American Transmission Company [2005b, p. 4].

<sup>6</sup> Retirements beyond 2003-2005 timeframe were unknown.

<sup>7</sup> This scenario provides a basis to assess the impact of differential bid prices of generators in Wisconsin with respect to that of neighboring regions.

<sup>8</sup> This scenario provides a means to address the ‘what if’ question of high generator offer prices in Wisconsin vis-à-vis generator offer prices in the broader region.

network; the path of primary fuel prices; maintenance schedules; future generator siting; and the structure and scope of regulation. Indeed, the location and timing of the siting of new generating units cannot be readily known at the time that transmission service providers commit to transmission plans. Arguably, a good plan is one that is robust in the sense of providing positive net benefits over a range of plausible future market and system conditions.

Third, power systems harbor strong network externalities. Power flow externalities are a direct result of power system physics, and are implicit in regional power prices. Accordingly, the benefit-cost framework for assessing and comparing transmission projects must involve large-scale network models that integrate, with sufficient accuracy, the three essential elements of regional power markets and systems in the future – namely, load patterns, the siting and bidding (self-nominating dispatch) behavior of generators, and the transmission network topology.

Market simulation software (such as PROMOD) assumes perfectly efficient centralized dispatch. In virtually all applications, the difficult-to-quantify impacts of physical and institutional constraints on how system operators actually operate power markets are ignored. To compensate for the assumption of perfect market efficiency, modeling restrictions can be artificially inserted into the optimization software, though these restrictions often provide poor approximations for real-world agent behavior within regional markets. This is especially a concern when the assessment is over distant time horizons, such as the case with estimating the benefits and costs of transmission under an assumed state of the world in 2013.

Fourth, network models cannot adequately assess certain direct and indirect effects associated with transmission expansion. These non-trivial effects can include enhancement of reliability, risk mitigation, improved optionality and choice for participants, and local economic benefits. The analyses obtained through regional market simulation focus on the more easily quantifiable energy savings resulting from transmission projects rather than on other benefits and costs of expansion, but are not easily quantified. While market simulation techniques provide only a limited view of the effects of transmission projects, the approach can become the focal point of the net benefit assessment and the decision making process.

Fifth, the transmission service provider has only limited knowledge of the regional environment in which decisions are made and resources are committed. Furthermore, the margin of estimation error associated with a study of this kind is heightened by the fact that the wholesale power market in the Midwestern region has been subject to a sea change wrought by the Midwest Independent Transmission System Operator moving to a Day 2 Market environment in April 2005. The long-term impacts of such a significant structural shift in the wholesale markets simply cannot be fully foreseen and quantified at this time.

Assessment of transmission plans covers many dimensions of net benefits, and is complicated. The task at hand, then, is to define and implement analysis and modeling procedures that are adequate to the challenge, but yet not too burdensome and unwieldy. It is in this spirit that the analysis conducted by ATC planners and CA Energy Consulting has been developed. Specifically, the approach taken is to conduct fairly in-depth analysis of the direct benefits and costs for a designated forward year, coupled with quantification of several indirect impacts. This approach considers relevant outcomes and their implications, and thus serves as a foundation for informed decision-making.

## 2. REDUCED OPERATING RISKS

This section assesses the benefits of reduced uncertainty in the costs of producing and delivering electricity by transmission expansion:

- Mitigation of Fuel Cost and Generation Capability Risks
- Improved Operating Flexibility

The first factor refers to the reduced risks of fuel cost and generation capability afforded by expansion of high-voltage transmission. The second factor refers to the mitigation of risks associated with the increased discretion and flexibility in the scheduling of maintenance of transmission and generation facilities. Because risk is costly, risk mitigation translates directly into net benefits that ultimately accrue to the retail service providers and electricity consumers in ATC's service territory.<sup>9</sup>

### 2.1. Mitigation of Fuel Cost and Generation Capability Risks

Expanded transfer capability within and into ATC's service territory can provide means for better managing future risks related to primary fuels and the technologies used in power generation. Because risk is costly to participants in wholesale markets and to retail consumers, cost-effective reductions in risks are beneficial to consumers. Transmission investment would thus reduce electricity price risk, translating directly into additional wholesale price reductions.

The increased transfer capability resulting from any one of ATC's ASI projects can reduce two major types of risk:

- *Fuel Cost Risks.* By increasing the access to generation both within and outside of ATC's footprint, an ASI project can help to hedge primary fuel price risks. For example, if the relative price of natural gas in ATC's service territory unexpectedly rose, stakeholders in the ATC footprint might be able to increase imports of non-gas-fired electricity from neighboring areas.
- *Generator Capability Risks.* By increasing the access to generation both within and outside of ATC's footprint, an ASI project can provide an effective means to partially hedge the uncertain availability of generation within the footprint and the surrounding region. Generator units are out of service from time to time because of unforced outages, routine annual maintenance and, on occasion, because of large-scale overhaul or replacement of power generation equipment. Furthermore, unusual contingency events and system conditions can, in spite of their low likelihood of occurrence, have substantial impact on total costs, should they occur.<sup>10</sup> Even when generation uncertainties do not adversely affect reliability, the availability of greater import capability can help mitigate the price spikes that can accompany generator outages.

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<sup>9</sup> The PROMOD analysis estimates expected costs, but does not recognize uncertainty in costs.

<sup>10</sup> An example is the exceptionally low precipitation experienced east of the Rockies over recent years, and which continues today. Reduced river flows result in reduced hydroelectric output, with a corresponding increase in the output of thermal units. Because these phenomena to a large extent, are unanticipated, they are not readily incorporated into conventional contingency planning, as there is little history upon which to gauge the inherent risks.

The increased transfer capability of an ASI project can enable ATC and its stakeholders to better manage the foregoing risks. The likely impact is that average and marginal production costs (i.e., as represented by LMPs) will have less variation across uncertain future market and system states. Accordingly, risks faced by retail consumers will decline along with the costs incurred by consumers to manage those risks.

### 2.1.1 Approach

The benefits of fuel and generation technology diversity can be estimated in two ways. The first method involves the monetization of fuel and generation capability risks, where energy cost impacts of fuel prices are simulated over several sets of possible primary fuel prices.<sup>11</sup> A second approach, which is utilized herein, draws upon key scenarios – sensitivity cases – to infer the benefits of fuel and generation capability risk diversity. The sensitivity case results, which are a basis for quantifying the change (reduction) in risks, are then ranked according to a defined MCA scoring metric.<sup>12</sup> Both approaches utilize simulation models (like PROMOD) that mimic the dispatch actions of merchant generators and utilities, and then determine power production costs for the identified scenarios of fuel prices, generator unit availability, and potentially large-scale contingency events.<sup>13</sup>

### 2.1.2 Findings

Table 2 shows our initial findings concerning the risk reductions attending improved fuel cost diversity. The first row of the table shows the variability (as measured by the standard deviation) of energy cost outcomes for the Base Case and for each of the five projects over fuel price scenarios for the year 2013, where dollars are measured at 2005 price levels. The second row shows the reduction in the standard deviation of operating costs that results from each project. The standard deviation reduction is equal to the standard deviation of the Base Case minus the standard deviation associated with the respective project.<sup>14</sup>

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<sup>11</sup> To calculate the benefits of fuel and generation technology diversity of particular transmission projects using this approach, analysis would be performed for the Base Case and for each of the candidate expansion options. The change in the variance or standard deviation of energy costs between the Base Case and each of the expansion cases would be a measure of the fuel and technology diversity benefit of each of respective expansion options. The measure of risk can then be “priced” with an appropriate risk adjusted cost of capital within a Value-at-Risk (VaR) metric, which can then be integrated into the benefit-cost framework.

<sup>12</sup> A third alternative is to use a descriptive indicator of improved fuel diversity, and to then score the indicator. For example, the indicator could be defined as the change in the percent of hours that gas technology is on the margin in each of the expansion cases relative to the Base Case. The notion of “diversity” of each case could then be defined by this percentage, where a lower percentage implies greater fuel and technology diversity.

<sup>13</sup> Market results reflect the behavior of participants in power markets – merchant generators and load serving entities including integrated utilities and local distribution companies – and are manifest in individual unique power prices at all locations within the network; and production costs that, in turn, reflect the running costs and MWh quantities of the various generating units of the Upper Midwest region.

<sup>14</sup> Standard deviation is a well-recognized and often used statistical measure of uncertainty in the range of outcomes. Generally speaking, a relatively large standard deviation suggests a wider range of possible outcomes – in this case, energy costs –and of risk.

The merit scores are proportional to the standard deviation change. The largest standard deviation change is set equal to score of 10.

**Table 2**

**Benefits of Fuel Diversity of Access Initiative Expansion Options:  
Reduced Risks In Annual Energy Costs Associated with Electricity In Wisconsin**

(millions of 2005 \$, assessed at market value)

	<b>Base Case</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Standard Deviation of Operating Costs	\$267.7	\$185.5	\$197.9	\$184.9	\$188.1	\$182.3
Reduction in Standard Deviation relative to Base Case		\$82.2	\$69.9	\$82.9	\$79.6	\$85.4
<b>Merit Score</b>		9.6	8.2	9.7	9.3	10.0

Table 3 quantifies the impact of the projects in mitigating the risks of generation outages. In this table, the variability of outcomes is measured by the range of possible future operating cost scenarios (highest cost future minus lowest cost future) for 2013. The scenarios used in the determination of the range incorporate three scenarios that depend upon the availability of nuclear generators and of the Elm Road Unit 3.<sup>15</sup>

The first row of Table 3 reveals the range of operating costs for the Base Case and each of the projects, measured at market value. The second row shows the reduction in the range of operating costs obtained by each project with respect to the Base Case. A reduction in the range of energy costs constitutes a reduction in risk, and is thus a net benefit. The third row presents the merit scores for each of the project options. As before, a high score of 10 is assigned to the option with the greatest decrease in the range of plausible future energy costs (Salem). The merit scores of the other options are proportionately scaled with respect to that of the Salem option.

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<sup>15</sup> Subsequent analyses may involve a larger number of potential operating cost outcomes. Nonetheless, the cases considered appear to capture a significant range of outcomes.

**Table 3**  
**Mitigation of Risks of Generation Capability:**  
**Reduced Risks In Wisconsin Electricity Generation Costs**  
(millions of 2005 \$, assessed at market value)<sup>16</sup>

	<b>Base Case</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie<sup>17</sup></b>
Range of Operating Costs	\$483.6	\$430.7	\$408.6	\$435.3	\$427.8	\$564.8
Reduction in Range relative to Base Case		\$52.9	\$74.9	\$48.3	\$55.8	-\$81.3
<b>Merit Score</b>		8.6	10.0	8.3	8.8	0

## 2.2. Improved Operating Flexibility

*Operating Flexibility* refers to the possibility that transmission expansion can provide greater flexibility in the scheduling of transmission maintenance and in reconfiguring the system during emergencies. Greater flexibility allows ATC greater choice about when facilities can be removed from service for routine maintenance, upgrade of existing equipment, addition of equipment, and replacement of equipment. This can reduce maintenance costs, reduce power production costs, and improve power system reliability.

Furthermore, improved operating flexibility provides planners of transmission and generation facilities with greater choice in the selection of facility down time over a variety of uncertain future conditions. Greater scheduling flexibility results in reduced variation in production and reliability costs, as the power system is better able to respond to actual system conditions that deviate from expected conditions. It can also allow quicker response to system emergencies.

The improved operating flexibility in Wisconsin, arising from the various transmission projects of the access initiative, might be measurable through simulation methods. Specifically, power system software such as PROMOD, can be used to simulate the total production costs and LMPs for the Wisconsin region. Such simulations would be conducted over selected scenarios of maintenance events (down time) on pre-defined facilities of ATC's network, where down time of the facilities is varied over the course of an annual period.

The PROMOD simulations of the identified maintenance scenarios would be conducted for the Base Case and for the ASI projects. The difference (i.e., reduction) in total production costs and

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<sup>16</sup> The assessment of the direct impacts of transmission expansion is highly specific to the underlying market structure and (thus) analysis approach. Here, the use of market value for the loads is selected as the criterion in order to represent the relative welfare gains to the loads taken separately because the load side of markets would be the main focus of regulatory inquiry. Other approaches are also available.

<sup>17</sup> The merit score for Prairie is constrained to be no less than zero.

LMPs across the simulations of the maintenance scenarios would be calculated for the Base Case and project cases. The change in production costs could then be ranked by merit scoring.

Because we do not have the data and analytical results that are needed to quantify this factor, we are not able to assess this factor at the present time.

### **3. RELIABILITY BENEFITS**

Transmission upgrades generally improve power system reliability. Upgrades can also be used to allow for a reduction in reserve requirements while holding reliability unchanged. More generally, transmission upgrades can yield a combination of improved reliability and reduced reserve requirements.

This section considers two Other Factors that collectively gauge reliability and benefits of the change in the level of reliability attributable to the transmission projects of the Access Initiative. The measures include:

- Reduced Expected Unserved Energy
- Improved System Performance

The first factor, Reduced Expected Unserved Energy, is the value of improved reliability to retail consumers, measured by the reduction in the outage costs borne by consumers due to service failures. The second factor, Improved System Performance, includes two attributes related to system reliability: voltage limits and likelihood of cascading failures.

#### **3.1. Reduced Expected Unserved Energy**

Expected unserved energy (“EUE”), for purposes of this analysis, refers to the quantity of energy that is expected to be unserved due to events solely at the bulk power level. Such events arise from a combination of: a) generation supply that is inadequate to meet load; and b) transmission limitations that prevent generation supply from reaching loads. EUE is a measure of transmission system capability to continuously serve all loads at all delivery points while satisfying all reliability criteria. EUE roughly equals the product of: a) the probability of outages occurring; b) the MW magnitude of outages; and c) the hours of duration of outages. EUE is thus measured in MWh. Improvements in reliability are manifest as reductions in EUE. EUE can be monetized and potentially added in with other monetized benefits for each of the various transmission options.

##### **3.1.1. Approach**

Assessment of EUE involves information and data regarding the frequency and duration of each contingency event and unserved megawatts of load for each of the contingencies. The unserved megawatt load is determined by reducing the level of loads, in amounts and at various locations within the system optimally, such that all system violations are resolved with the minimum amount of load reduction. The remaining level of load subsequent to load shedding represents the maximum capability of the system, given the state of the system. The unserved megawatts of load for each contingency are then multiplied by the duration and frequency of the contingency. In brief, the likelihood that each contingency event can be quantified as a summary measure of

EUE is the sum of all the probability-weighted unserved megawatts for each contingency. This single measure, which can be viewed as an EUE index, indicates the relative performance of system reinforcement, and provides a means to rank and compare project alternatives.

The analysis utilizes the *Physical Operation Margin* and *Optimal Mitigation Measure* (“POM” and “OPM” software of V&R Energy to determine EUE. The analyses incorporate the historical probability of transmission facility outages along with the expected load, generation and topology of the transmission system for 2013 in order to determine the MW and duration of load unserved.

The reliability merit of transmission system additions is the change in the aggregate index EUE. The value of the change in reliability (i.e., reduced EUE) is the decrease in consumer outage costs associated with the change in EUE.

### 3.1.2. Data

The relevant data for estimating expected outage costs include system states defined by the status of network topology, generators, and loads; estimates of the incremental change in EUE induced by the transmission projects; benchmark levels of overall customer energy consumption (and MW of load); and estimates of the costs of unserved energy.

Line outage probabilities are derived from actual experience over the years 1997-2003. Actual line outages per hundred mile-years are calculated separately for each voltage class. Total reactance and total miles are calculated for each voltage class in order to convert outages per hundred mile-years to outages per ohm-years. Outages per year, or outage frequency, are calculated for each branch of the network as the product of that branch’s reactance and outages per ohm-years. Actual line outage durations are determined separately for each voltage class. Each branch’s outage probability is based on the product of its outage frequency and outage duration.

To quantify EUE over the course of a year, ATC studied three load levels: the summer peak load, 80% of summer peak, and 60% of summer peak. EUE, as estimated for each load level, is multiplied by the frequency that the system is at that level. The annual EUE is then calculated by summing the estimates of EUE across the three load levels. The probability of being at the defined load levels is determined from 2001 through 2003 load data, as shown below in Table 4. For the purpose of the immediate study, the summer peak EUE is multiplied by 0.037, the frequency shown in percentage terms that the load is greater than 80% of the summer peak over the selected timeframe.

**Table 4**  
**Load Level Frequencies, ATC Power System**

Load Level (% of summer peak)	% of time			
	2001	2002	2003	Average
Load > 80%	3.5	4.6	2.9	3.7
60% < Load < 80%	44.5	48.2	45.7	46.1
Load < 60%	52.0	47.2	51.4	50.2

Studies of the costs of unserved energy are fairly numerous. A literature review underlying the analysis herein found a total of 97 estimates of residential outage costs on a per-kWh basis. The median of these observations is \$2.28/kWh stated in (1999 \$), with one-sixth of the values falling below \$0.30 and one-sixth of the values exceeding \$7.67/kWh.

For commercial customers, 43 estimates of outage costs reported on a per-kWh basis were found. The median of these values was \$16.36, with one-sixth falling below \$0.12 and one-sixth exceeding \$27.44, (all values stated in 1999 \$).

For industrial customers, we found 49 estimates of outage costs reported on a per-kWh basis. The median of these values was \$8.48, with one-sixth falling below \$0.39 and one-sixth exceeding \$24.67 (all values stated in 1999 \$).

Table 5 below summarizes the estimates that we have found, showing the range of values that covers two-thirds of the estimates. This is the range that we use to calculate our results. The Appendix of this *Other Factors Report* describes the sources of information that underlie the figures shown in Table 5.

**Table 5**  
**Distribution of per-kWh Outage Costs**  
(1999 \$ per kWh Unserved)

Class	# of Observations	17th Percentile	50th Percentile	83rd Percentile
Residential	97	\$0.30	\$2.28	\$7.67
Commercial	43	\$0.12	\$16.36	\$27.44
Industrial	49	\$0.39	\$8.48	\$24.67

### 3.1.3. Analysis Findings

EUEs are estimated for each Access Initiative project and then tabulated. Results are shown in Table 6 below. The unserved megawatt load and probabilities (i.e., frequency of each contingency of a given duration) for each of the system states are utilized to compute EUE, which is the sum of the unserved energy weighted by the probability of each of the contingency

events and the frequency of the identified load level. The level of EUE indicates the relative performance for a given transmission project. The results of the analysis are shown in Table 6.

**Table 6**  
**Reduced Unserved Energy for the Access Initiative Projects**

Access Initiative Project	Expected Unserved Energy (MWh/yr)					
	Summer Peak (SP) at N-0	SP at N-1 (Load Level $\geq$ 80%)	SP at N-1 (60% $\leq$ Load Level $\leq$ 80%)	SP at N-1 (Load Level $\leq$ 60%)	Total Probability -Weighted EUE	$\Delta$ EUE Compared to Base Case
<b>Load Level Prob</b>		0.037	0.461	0.502		
<b>Base Case</b>	29,310	1,692	765	206	31,974	0.0
<b>Paddock</b>	22,564	1,025	585	154	24,330	-7,643
<b>Salem</b>	4,915	1,066	607	135	6,725	-25,249
<b>Lower-Voltage</b>	26,166	903	804	152	28,026	-3,948
<b>Byron</b>	4,357	1,782	625	191	6,956	-25,018
<b>Prairie</b>	25,913	1,532	756	188	28,391	-3,583

Table 7 monetizes the EUE results presented in Table 6. The EUE benefit of each transmission project is the EUE reduction due to that project, which is shown both in the rightmost column of Table 7 and the second data row of Table 7. This benefit is then multiplied by \$10.27 per kWh, which is the mean value of consumer outage costs shown in the “50%” column of Table 5, weighted by class energy sales, stated in 2005 \$.

**Table 7**  
**Reduced Outage Costs Obtained by Access Initiative Projects**

(millions of 2005 \$)

	Base Case	Paddock	Salem	Lower-Voltage	Byron	Prairie
EUE (MWh)	31,974	24,330	6,725	28,026	6,956	28,391
$\Delta$ EUE with regard to the Base Case		-7,644	-25,249	-3,948	-25,018	-3,583
Gains Realized by Consumers		\$78.5	\$259.2	\$40.5	\$256.8	\$36.8
<b>Merit Score</b>		3.0	10.0	1.6	9.9	1.4

The MWh estimates of Expected Unserved Energy of the Base Case are unusually large because of the prevalence of voltage violations within the case. Accordingly, the reductions (decrements) in EUE attributable to the project options may be overstated, though that is not known at this time. Furthermore, the voltage violations may possibly be managed with solutions other than the project options of the Access Initiative, such as the strategic placement of capacitor banks within ATC's network. These other solutions, targeted to voltage issues, may be less costly than the project options. However, high-voltage solutions may also play a vital role in resolving the voltage issues.

Nonetheless, resolution of voltage violations of the Base Case, which would likely result in reduced EUE of the projects with reference to the Base Case, may remain relatively unchanged leaving the *order* of the merit scores of the projects about the same.

### **3.2. Improved System Performance**

“System performance” includes two dimensions of benefits: the effects of voltage limits on the transmission system's transfer capability; and the likelihood of cascade events. A transmission upgrade creates system performance benefits if it increases transfer capability by improving voltage performance and also if it reduces the likelihood of cascading failures.

As a general rule, the constraints on the major flowgates of ATC's power network are thermal. On occasion, however, the voltage constraints are reached first, such that the effective constraints are indeed voltage-related. It is under these conditions where the improved voltage performance results in greater transfer capability and thus reduced energy costs for customers in the ATC footprint.<sup>18</sup>

The second aspect of system performance is the possible reduced likelihood of cascading power outages, which is reflected as improved reliability to the retail electricity consumers in Wisconsin. Large-scale cascading power failures, like the cascades of July 2 and August 10 in 1996 in the Western System and again on August 14, 2003 in the Eastern System, are enormously costly events. Diagnostic analysis of these and other events reveals that the root cause often involves several factors, including the lapse of system observability, low-voltage conditions leading to near voltage collapse, and the mis-operation of system relays.

#### **3.2.1 Approach**

ATC's Access Initiative projects can potentially improve power system reliability by reducing the likelihood of cascading outage events.<sup>19</sup> Cascading events cannot be accurately predicted. However, researchers have recently discovered that, across a large number of cascading outage events, fairly clear system relationships exist between the level of loadings on lines (MW flows) within regions, and the size (and thus the costs) of the lost load.<sup>20</sup>

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<sup>18</sup> No empirical studies have been conducted into the frequency with which voltage constraints are reached before thermal constraints. However, the frequency is typically very small on systems in the Midwest region.

<sup>19</sup> See Kirschen and Strbac [2003] and Reppen [2004].

<sup>20</sup> See Carreras, Newman, and Dobson [2004].

### 3.2.2. Analysis Findings

We assess Improved System Performance by using the merit scoring approach of MCA, where the quantity metric is the improved transfer capability due to the better voltage control available because of transmission upgrades. Improvements in voltage performance can be determined with analysis tools specifically geared to voltage assessment, such as the Voltage Security Assessment Tool (“VSAT”). VSAT determines the transmission upgrades’ incremental changes in the frequency of low-voltage conditions in various system states.<sup>21, 22</sup>

Table 8 presents results for the analysis of Improved System Performance. The first row shows ATC’s maximum transfer capability with and without each of the projects. The second row shows the improvement in maximum transfer capability that is due to each project. The third row uses a 0 to 10 scale to score transmission projects, where 0 represents the “least preferred” impact, and 10 represents the “most preferred” impact.

**Table 8**

#### **Benefits in Voltage Transfer Capability Resulting From Improved Voltage Performance**

	<b>Base Case</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Maximum Transfer Capability (MW)	2,465	3,715	3,834	2,493	3,862	3,056
Incremental Improvement in Capability		1,250	1,369	28	1,397	591
<b>Merit Score</b>		8.9	9.8	0.2	10.0	4.2

## **4. POWER SYSTEM EXTERNALITIES**

This section considers three factors that have benefits or costs that are related to both production costs and reliability. These factors are:

- Benefits Realized by Neighboring Systems
- Improved Value of Other Planned Projects

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<sup>21</sup> Over-voltage conditions can also be a problem, though this is relatively unlikely.

<sup>22</sup> Currently, the analysis of cascading failures resides within the realm of power system research. With sufficient resources, it may be possible to quantify the benefits of reduced cascading failures through the use of software akin to that of EPRI’s Transmission Reliability Evaluation Large Scale Systems (TRELSS). Such software would model randomly determined contingency events over a range of various system states of the transmission system in ATC’s regional neighborhood. In order to provide a means to simulate truncated and realized cascades of facility outages, the software should model groups of system components (protection control groups). The simulations involve many model iterations, which yield a large set of case results that could reveal the frequency with which ATC’s power system would potentially enter threshold states where cascade events would be possible.

- Increased Transfer Capability Attributable to Higher Thermal Limits

#### 4.1. Benefits Realized by Neighboring Systems

Network expansion in one location can yield benefits in many other locations across the region, a characteristic that is sometimes referred to as “network externalities.” The implication is that ATC’s Access Initiative projects may convey substantial benefits to market participants within the upper Midwest region outside ATC’s service territory. These benefits can include the direct effects of reduced costs for power supply, improved reliability, and increased asset utilization that translate into lower retail electricity prices. Benefits can also be in the form of indirect effects akin to those discussed in this report, such as economic development and improved access of renewable resources to the 345 kV system.

##### 4.1.1. Approach

The Benefits to Neighboring Systems can be quantified if information regarding the surrounding power systems and market context are readily available, and if resources are sufficient to conduct extensive analyses. That is, simulations of the region’s power market can provide the basis to assess the net changes in generation costs and reliability in service territories outside of the ATC footprint.

Because of limits of information and resources, we qualitatively assess Benefits to Neighboring Systems using the MCA merit scoring method. Each of the projects of the Access Initiative is assigned a score on the basis of the presence of the following five potential benefits:

- Direct improvement in *occasional* transfer capability due to reduced constraints
- Direct improvement in *chronic* transfer capability due to reduced constraints
- Mitigation of chronic transfer limit due to constraints
- Improved stability response
- Increased backbone infrastructure

A merit score is then awarded on the basis of the project’s total points made proportional to that of the highest scoring project, which is set equal to 10. The expected benefits attending each of the projects are described briefly below:

##### *Paddock – Rockdale Circuit #2*

- Directly reduces one constraint on the Alliant-West system (Hazelton-Dundee 161kV line) and one chronic limitation on the Dairyland system (Cassville-Nelson Dewey 161kV path constraint) and mitigates one chronic limitation on the Alliant-West/Dairyland Power System (Lore-Turkey River-Cassville 161kV path constraint)
- Provides 345 kV infrastructure through the DPC system

##### *Salem – North Madison*

- Potentially provides moderate improvement in Quad Cities (ComEd/MEC) and Cordova (MEC) stability response

- Directly reduces three constraints on the Alliant-West system (Hazelton-Dundee, Salem-Maquoketa and Davenport-East Calamus 161kV lines) and one chronic limitation on the Alliant-West/Dairyland Power system (Lore-Turkey River-Cassville-Nelson Dewey 161kV path constraint)
- Provides 345kV infrastructure through the ALTW and DPC systems

*Lower-Voltage*

- Directly reduces one chronic constraint (Lore-Turkey River-Cassville-Nelson Dewey 161kV path constraint) on the Alliant-West/Dairyland Power System

*Byron-North Madison*

- Potentially provides moderate improvement in Byron stability response
- Directly reduces one constraint on Alliant-West system (Hazelton-Dundee 161kV line) and mitigates one chronic limitation on the Alliant-West/Dairyland Power system (Lore-Turkey River-Cassville-Nelson Dewey 161kV path constraint)
- Provides 345kV infrastructure through the NW territory of the ComEd system

*Prairie Island – Columbia*

- Directly reduces one chronic limitation on the Dairyland system (Cassville-Nelson Dewey 161kV path constraint) and mitigates one chronic limitation on the Alliant-West/Dairyland Power system (Lore-Turkey River-Cassville 161kV path constraint)
- Potentially improves the Minnesota-Wisconsin Stability Interface (MWSI) flowgate capability resulting in a direct improvement in transfer capability. In addition, a reduction in the stability limit (stability response) can be potentially realized, thus expanding the Twin Cities export capability.
- Provides 345 kV infrastructure through the Xcel Energy, RPU and DPC systems

4.1.2. Analysis Findings

A summary of the qualitative assessment of the Benefits to Neighboring Systems is provided in Table 9 below.

*(see following page)*

**Table 9**

**Presence of Potential Benefit Attributes Realized by Neighboring Systems**

Performance Objective/Criterion	Access Initiative Projects				
	Paddock	Salem	Lower-Voltage	Byron	Prairie
Direct Improvement in Transfer Capability	X	X		X	X
Direct Reduction in Chronic Transfer Constraints	X	X	X		X
Mitigation of Chronic Transfer Limits	X			X	X
Potential Improvement in Stability Response		X		X	X
Increased Backbone Infrastructure	X	X		X	X
<b>Total Points</b>	4	4	1	4	5
<b>Merit Score</b>	8.0	8.0	2.0	8.0	10.0

**4.2. Improved Value of Other Planned Projects**

This factor captures the effect of each transmission project on the net value of other transmission projects. Positive effects are better than negative effects.

In general, transmission projects can either increase or reduce the benefits of other planned transmission projects. As a simplification, where transmission projects are *in series*, with one transmission project delivering power to a location from which another transmission project can relay the first project’s power, the transmission projects will tend to increase each other’s values. Where transmission projects are *in parallel*, where flows over one project will reduce the power that would flow over the other projects, the projects will tend to reduce each other’s values, even to the point that one project can eliminate the need for another project. The elimination or delay of a project as a consequence of the introduction of another project has the benefit of the avoidance or deferral of capital and non-capital costs.

Some, though not all, of the benefits of enhancing the value of other planned projects are implicit within: a) ATC’s estimates of the production cost savings due to investments; and b) estimates of reliability benefits. However, benefits from the AIS projects also accrue in the form of investment cost savings, and it is these benefits that the analyses focus on in this section.

#### 4.2.1. Approach

With sufficient resources and information, one possible way of analyzing the impact of one transmission project on another project would be to assess the incremental difference in production costs and other quantifiable impacts of a given project with and without another project.<sup>23</sup>

An alternative approach is to estimate the capital charges and fixed operations and maintenance expenses that are avoided if a project's completion enables other projects to be delayed or eliminated altogether from the long-range plan. These avoided costs are manifest as reductions in annual direct cost for transmission services during some years.

#### 4.2.2. Findings

Following the second approach, ATC was able to determine that only the Salem project would result in elimination or deferral of reliability projects identified in the TYA. The value in 2005 dollars of this deferral was estimated to be \$3,640,102. This value can be added directly to the other monetized benefits and costs for the Salem project estimated by ATC. However, the implicit merit score would be 10 for the Salem project, and zero for the other project options.

### 4.3. Increased Transfer Capability Attributable to Higher Thermal Limits

Transfer capability refers to the maximum level of power that can be imported into the ATC service territory under various market and system conditions. It is measured as the maximum megawatts of simultaneous import capability from neighboring systems. In general, the simultaneous import capability is specific to the distribution of flows across ATC's interties. Given the locations and levels of loads and the locations and costs of generation, the maximum transfer capability can only rarely be attained because flow patterns are seldom optimally distributed among the flowgates of the interties.<sup>24</sup>

The intent of the ASI is to expand the transfer capability of ATC's transmission system and, as a consequence, the expected costs of energy should be reduced and concomitantly the reliability of the grid increased to electricity consumers in ATC's footprint. In addition, the expansion options

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<sup>23</sup> The impact of Project A on Project B equals the sum of the following elements: net production cost impacts of Project A, which are the production impacts of Project B *with* Project A minus the production cost impacts of Project B *without* Project A; plus net EUE value impacts of Project A, which are the EUE value impacts of Project B *with* Project A minus the EUE value impacts of Project B *without* Project A; plus net reserve requirement cost impact of Project A, which are the reserve requirement impacts of Project B *with* Project A minus the reserve requirement impacts of Project B *without* Project A; plus the present value of the capital cost savings of any postponement of Project B due to implementation of Project A.

<sup>24</sup> Given generator bids and locational load patterns, total system costs are minimized through the application of optimal power flow (OPF) techniques. The OPF solution is optimal – i.e., least cost – in the short run given load patterns, network topology, and generator bids, and is reflected in efficient locational prices. Nonetheless, the solution may not use interties most efficiently because of the inherent mismatch between load patterns and transmission capability. The problem is a result of two factors: a) the indivisibility and lumpiness of transmission facilities, which are installed in sizable increments of capability, and b) forecast uncertainty regarding future market conditions at the time of investment in transmission.

will enable ATC and utilities to better respond to various uncertainties and risks inherent to future market and system conditions.

The benefits associated with increased transfer capability of the Access Initiative projects are incorporated into: a) the estimates of the direct production cost savings; b) the value of the reliability improvements, as reflected in reduced expected unserved energy (EUE) benefits, and c) the enhanced capability to respond to uncertainty and risks. These benefits are quantified in the analyses contained elsewhere in this report<sup>25</sup> and in the companion report prepared by ATC.

#### 4.3.1. Approach

For each transmission project, incremental transfer capability is measured as the incremental increase in the maximum simultaneous import capability over ATC's interties with neighboring systems.<sup>26</sup> We translate incremental transfer capability into merit scores by first assigning a value of 10 to the project that has the most incremental transfer capability and then assigning proportionally smaller values to projects with less incremental transfer capability.

The incremental improvement in physical transfer capability attributable to reduced thermal constraints can be determined by applying specialized power system software such as Maximum Utilization of System Transfers (MUST), which estimates maximum transfer capability. These estimates of transfers are then assessed with the MCA merit scoring approach.

#### 4.3.2 Analysis Findings

The first row of Table 10 shows the MUST estimates of physical transfers for the Base Case and for each of the five candidate projects. The second row shows the incremental transfer capability due to each of the projects, where the values each equal the transfer capability with the project minus the transfer capability under the Base Case. The merit scores are proportional to the incremental transfer capability figures, with the project having the largest increase in transfer capability receiving a 10.

*(see following page)*

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<sup>25</sup> See the sections of this report entitled *Mitigation of Fuel and Generation Capability Risk, Benefits of Improved Operating Flexibility, Benefits of Improved Reliability (EUE), Benefits of Improved System Performance, and Benefits of Increased Geographic Diversity of the 345 kV Network*.

<sup>26</sup> Maximum simultaneous transfers can be determined for off-peak, typical, and peak load conditions; and for winter and summer timeframes.

**Table 10**

**Increased Thermal Transfer Capability Obtained From Access Initiative Projects**

	<b>Base Case</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Transfer Capability (MW)	1,913	2,789	3,342	3,166	3,094	3,118
Incremental Transfer Capability (MW)		876	1,429	1,253	1,181	1,205
<b>Merit Score</b>		6.1	10.0	8.8	8.3	8.4

**5. ENVIRONMENTAL BENEFITS AND COSTS**

This section considers three categories of benefits related to environmental quality. These are:

- Societal Impacts
- Environmental Externalities
- Access to Renewable Resources

Societal Impacts and Environmental Impacts have value flows that occur outside electricity markets rather than within electricity markets. Access to Renewable Resources is a benefit to the extent that ATC stakeholders and public policy choices prefer generation resources that are perceived as environmentally cleaner than other generation resources, such as fossil-fired units.

**5.1. Societal Impacts**

Societal Impacts are “non-environmental” siting impacts, such as Electro Magnetic Fields (EMF) and impacts caused by visual aesthetics. As a matter of policy, ATC’s approach is to exhaust all opportunities for corridor sharing with existing transmission lines.<sup>27</sup> For the interconnection projects to the south, southwest and west, opportunities for corridor sharing are significant.

**5.1.1. Approach**

Because the specific routes of the Access Initiative projects are not known at this time, we assess Societal Impacts qualitatively, using the MCA merit scoring method.<sup>28</sup>

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<sup>27</sup> Wisconsin law requires corridor sharing.

<sup>28</sup> The assessment of the Societal Impacts depends upon sufficient information regarding specific transmission line routes for each of the respective projects and the incremental impacts of visual aesthetics and possible EMF. Relevant studies are likely to reside in regulatory records and academic literature, particularly with respect to visual impacts of new transmission routes. The economic values associated with concerns about EMF may be more difficult to identify because of the ongoing controversy over the possible health effects of EMF.

For the project options considered in this report, the following miles of new right-of-way (“ROW”) have been identified.

*Paddock – Rockdale Circuit #2:* approximately 8 miles

*Salem – North Madison:* approximately 6 miles

*Byron – North Madison:* approximately 56 miles of new right-of-way

*Prairie Island – Columbia:* approximately 159 miles

### 5.1.2. Analysis Findings

The above approximations are used as the qualitative indicator of Societal Impacts, where fewer miles of new ROW are preferred. A merit score is determined on a basis of proportionality to the difference between the Lower-Voltage project, which receives a value of 10 given there are no new miles of ROW, and Prairie (Prairie Island-Columbia), which receives a value of zero since it has the largest number of miles – and thus the largest negative impacts. The results are shown in Table 11.

**Table 11**  
**Societal Impacts**

	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Miles of New Right-of-Way	8	6	0	56	159
<b>Merit Score</b>	9.5	9.6	10.0	6.5	0

Note that the scoring approach is altered to accommodate the sign reversal associated with the nature of societal impacts. Essentially, benefits are negative as the societal impacts are social costs.

## 5.2. Environmental Externalities

Environmental impacts of infrastructure projects typically center on land use; on land type including river crossings, streams, wetlands, state natural areas, state parks, national forests and parks, tribal lands, and special waters areas; and on threatened, endangered, and special concern species. At the preliminary stages of project planning and analysis, environmental impact assessment remains at a very high level, as quantification is limited by a lack of route specificity, which is necessary to identify and characterize the physical environment that is affected. Once specific projects and routes have been selected, environmental impacts can be investigated in greater depth. Analysis will possibly involve alternative routes and other steps that tend to mitigate impacts, such as the use of existing right-of-way as required by Wisconsin law.

### 5.2.1 Approach

The value of environmental quality assumes two dimensions. Both types of environmental value are related to the economic service provided by the physical environment. First, the direct use of the physical environment contributes to production – i.e., the output of goods and services provided by businesses, government agencies, and by households. An example could be canoeing or wilderness guide services. Rivers and wilderness areas provide environmental services as inputs into the production process of the service firms. A second example would be the services provided by an inland lake to households that enjoy water skiing.

Second, physical environments provide flows of non-use or passive use services. The value obtained by individuals in the form of passive use services also constitutes economic utility and worth, even where no direct involvement in the environment takes place. As an example, many individuals obtain value knowing that a large expanse of the Rocky Mountain range stretches north-south through the North America, even though they may only rarely visit this majestic landscape.

Assessment of environmental impacts involves: 1) the determination of quantity of the physical impacts, stated as reduced flows of environmental services; and 2) the foregone value associated with the impacts, stated in money terms. The physical impacts, in turn, involve estimates of how physical environments are disturbed. Estimates of the flows of services (impact quantities) are then multiplied by the estimated per-unit dollar value of impact.<sup>29</sup> The results are then stated on a present value basis using either societal or private rates of discount.

An alternative approach is habitat equivalency, where the environmental impacts (the quantities) and costs associated with an infrastructure project are compensated with the development of an alternative habitat of equivalent quality.<sup>30</sup>

### 5.2.2 Analysis Results

The routes of the AI projects are not specific enough to conduct the analysis described above. However, it is perhaps useful to summarize the projects with an initial assessment of the general areas involved, as follows.

*Paddock–Rockdale:* This project largely uses existing right-of-way, and no significant public lands were identified along the route of the existing corridor, though several county parks, and other public lands are scattered throughout the area. The area also includes the Rock River, Bass and Saunders Creeks, along with their tributaries, and tributaries to Koshkonong Creek, as well

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<sup>29</sup> The economic worth per unit of habitat can be determined with survey techniques including contingent valuation methods. These methods have been applied extensively, and a survey of the environmental economics literature, empirical studies, and regulatory filings can serve as a general guide.

<sup>30</sup> In this type of analysis, environmental impacts of a project are characterized by the reduction in key environmental services and the period over which these impacts are expected to be felt. The analysis then quantifies the amount of similar habitat that would need to be created in the future to provide a “present value” discounted flow of environmental services that is equal to the present value of the cost services. Critical inputs to this process are common metrics that can be used to summarize: a) the environmental services lost because of the project; and b) the environmental services gained as a result of a compensatory project.

as several wetlands and remnant prairies. The installation of new facilities along these routes may impact these environments in a transitory way.

*Salem-Spring Green-North Madison:* Similar opportunities are available. The route will recognize Nelson Dewey State Park, Governor Dodge State Park, Tower Hill State Park, Bluemounds State Park, Blackhawk Lake Recreational Area, Turkey River Mounds State Park (IA), White Pine Hollow State Forest Preserve, (IA), Lower Wisconsin State Riverway, numerous county parks, and other public lands. Sensitive resources include the Upper Mississippi River National Wildlife and Fish Refuge, Lower Wisconsin State Riverway, numerous Wisconsin State Natural Areas, several State Preserves and recreational areas, and also the Mississippi and Wisconsin Rivers and their tributaries.

*Byron-North Madison:* A number of corridor sharing opportunities are available including federal, state, and county highways, existing transmission facilities, railroads, and town roads. The specific routing of these new facilities would likely take account of Governor Nelson Dewey State Park, Blue Mound State Park, New Glarus Woods State Park, Brown-ton-Cadiz Springs State Recreation Area, Lowden State Park (IL), White Pines Forest State Park (IL), Lake Le-Aqua-Na State Recreation Area (IL), several designated wildlife areas, county parks, and other public lands.

*Prairie Island - Columbia:* Similar opportunities for corridor sharing are available. The route will take account of: Richard Dorer SP (MN), Parrot SP, Mid Bluff SP, Great River State Trail, Upper Mississippi River National Wildlife Refuge, La Crosse River State Trail, Rocky Arbor SP, Mirror Lake SP, Van Loon Wildlife Area, Coulee Experimental Forest, Buckhorn SP, Pine Island State Wildlife Area, Swan Lake State Wildlife Area. Several designated wildlife areas, county parks, and other public lands are scattered throughout the screening area. Two tracks of federal land may be impacted including the Upper Mississippi River National Wildlife Refuge and the Trempealeau National Wildlife Refuges. Tribal lands in the screening area belong to the Ho Chunk and Prairie Indian tribes. Large, contiguous wetland areas are concentrated near the Mississippi and Wisconsin Rivers, and there are minimal rivers/streams designated as Exceptional/Outstanding Resource waterways. Numerous Wisconsin State Natural Areas exist in the route screening area. The probability of encountering threatened, endangered, and rare species is high.

In addition, Table 12 categorizes, at the most general level, the types of physical environments that may be traversed.

**Table 12**  
**Percentage of Land Areas By Types Traversed by Access Initiative Projects**

	<b>Paddock</b>	<b>Salem</b>	<b>Byron</b>	<b>Prairie</b>
Agricultural Lands	66	64	54	33
Woodland and Wetland Areas	22	33	40	64
Developed Land Areas	7	3	6	3

### 5.3. Access To Renewable Resources

A benefit of increased transfer capability is that it can increase ATC stakeholders' access to Renewable Resources ("RRs") within and outside of ATC's service territory. This improved access can reduce the cost of satisfying Wisconsin's renewable portfolio standard ("RPS") by reducing the transportation costs of meeting the RPS, whether supplied by in-state or out-of-state renewable resources.<sup>31,32</sup> In particular, increased transfer capability could reduce transmission costs, especially congestion charges, that could increase the attractiveness of in-state RRs relative to conventional fossil resources and increase the attractiveness of out-of-state RRs relative to in-state RRs or conventional fossil resources.

This will be particularly important if the Wisconsin legislature increases the RPS minimum percentages along the lines of the recommendations of the Governor's Task Force ("Task Force Report"), which proposes that the statewide minimum percentage RPS be raised to 10% of total retail electric sales by 2015 and that state agencies purchase at least 20% of their electricity from renewable resources by 2010.<sup>33</sup> The increases in the RPS would be phased to coincide with ATC's planned expansions of the transfer capability. Thus, the RPS target would be raised to 6% in 2010 (two percentage points higher than the current 4% of retail sales that utilities are acquiring, which is above the current 2% requirement) and raised another 4% by 2015.<sup>34</sup>

To the extent that a new RPS of 10% cannot be met by Wisconsin utilities from in-state renewable resources in 2015 but can be met with out-of-state renewable resources in the Base Case (i.e., congestion in the Base Case does not affect the importation of out-of-state RRs to meet the 10% standard), the transmission projects will not provide any benefit through this factor. However, if congestion limits imports of economical out-of-state RRs to meet the 10%

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<sup>31</sup> Under Section 196.378(2), Wis. Stats. and Wisconsin Administrative Code PSC 118, all load-serving entities (LSEs) in Wisconsin are required to meet a renewable portfolio standard (RPS) under which qualified renewable resources must provide minimum percentage of their total retail electric sales. The percentage increases according to the following schedule: 2001, 0.50%; 2003, 0.85%; 2005, 1.20%; 2007, 1.55%; 2009, 1.90%; and 2011, 2.20%.

<sup>32</sup> An alternative description would also recognize that Wisconsin consumer demand for green resources may increase as those resources become more available to Wisconsin. An analysis of this factor would need to consider how renewable resource prices affect consumer demand for these resources. The effective supply function for Wisconsin would include both Wisconsin renewables and out-of-state renewables, where the costs of renewables include applicable transport costs. Improved transport capability would be manifest in the decreased transport costs of out-of-state renewable resources. Quantification would require estimates of the demand function for renewable resources in Wisconsin.

<sup>33</sup> See Wisconsin Governor's Task Force [2004, pp. 33-39].

<sup>34</sup> Since Wisconsin utilities currently have approximately 4% of total retail electric sales supplied from renewable resources (much of which comes from hydroelectric facilities), they would be required to increase their sales supplied from renewable resources by a total of 6 percentage points. Based on ATC's forecast of load of the five major utilities in Wisconsin, (forecast retail sales in 2013 are approximately 82 million MWh) a 10% RPS requirement would mean that in 2015, utilities would be required to make retail sales of approximately 9 million MWh from RRs. At a 30% capacity factor, this would require approximately 2,700 MW of renewable capacity. The Task Force Report indicates that about 450 MW of wind power projects are under development in Wisconsin, which would comprise about 17% of that capacity. Therefore, it is conceivable that greater access to out-of-state renewables (i.e., wind power projects) by 2013 would be critical to satisfying the RPS in 2015.

standard under the Base Case, at least some of the ASI projects could lower those transport costs and thus lower the costs of meeting the 10% standard.<sup>35</sup>

The Task Force Report acknowledges that utilities may not be able to meet the standards in 2010 or 2015 because of “transmission constraints that limit the deliverability of renewable electricity to the provider’s system.”<sup>36</sup> The Task Force Report recommends that, in these cases, the electric utility may receive an implementation delay in meeting the standards.<sup>37</sup> Consequently, a secondary benefit of some of the transmission projects that relieve transmission constraints is simply that the electric utilities will not have to engage in the administratively costly process of requesting an implementation delay.

In addition, an environmental benefit may also arise from particular transmission projects through reduced emissions from fossil generation. If, under the Base Case, Wisconsin utilities had to obtain delays in the implementation of the 2010 and 2015 standards (as proposed by the Task Force) because transmission constraints limit deliverability of in-state RRs or access to out-of-state RRs, the volume of emissions from fossil-fired generation will be greater for the period of the delay than they would be had the utilities gained immediate access to the in-state or out-of-state RRs. Thus, one benefit of the ASI projects can be defined in terms of the volume of emissions avoided.

In addition, the transmission projects considered by the ASI will increase the deliverability of in-state renewable resources as well as out-of-state RRs. This is related to several of the Other Factors discussed above, such as fuel and technology diversity. Also, as discussed under the Other Factors headed “Access to the High-Voltage Network” and “Geographical Diversity of the 345kV System,” by increasing the deliverability of RRs within the ATC service territory, the projects may enhance the optimization of geographical location of RRs, as well as encourage stronger growth of RRs, especially wind power.

### 5.3.1. Approach

In-depth quantitative analyses are not possible with the data available on renewable resources over the time frame considered in this study.<sup>38</sup> Absent such data, it is not possible to fully

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<sup>35</sup> Meeting resource adequacy (i.e., resource capacity) requirements within MISO and the State of Wisconsin through access to renewable resources outside of Wisconsin is made easier within the MISO market because, as defined under the MISO deliverability test, such resources only need be found “deliverable” to the aggregate MISO load rather than to Wisconsin-specific loads. “Deliverability” of a generating unit is one of the conditions imposed by MISO for a generating resource to be designated as a Network Resource by any Market Participant for purposes of meeting its firm reserves for resource adequacy under MISO’s Module E of its Open Access Transmission Tariff. However, the MISO “deliverability” test by itself does not eliminate the possibility that in 2013 RRs developed inside or outside of the state may not pass a “deliverability” test to be designated as new network resources for purposes of satisfying the RPS in the absence of relief of binding transmission constraints that one of the Access Initiative projects may provide.

<sup>36</sup> See Wisconsin Governor’s Task Force [2004, p. 37].

<sup>37</sup> *Ibid.*

<sup>38</sup> If a quantitative analysis were to be conducted to determine the benefits of increased transmission transfer capability in terms of renewable resources, PROMOD analysis could be used as the basis for comparing the cost of meeting the RPS minima under the Base Case with the costs of meeting the RPS minima under the five transmission projects. The analysis would examine as a sensitivity case the benefits under the proposed 10% standard in terms of

determine how the ASI transmission projects affect the access to RRs under a more aggressive RPS. Hence, the best approach is to identify the geographic dispersion and approximate capacities (or ranges of capacities potentially available at various market prices) of the various types of renewable resources within Wisconsin and in the neighboring states (Iowa, Illinois, Minnesota, and North and South Dakota in particular).

Given the information about where such resources are located and the approximate capacities available, the analysis of transmission projects can be conducted in a manner that gives due consideration to how particular expansion projects might facilitate RRs' availability and deliverability.<sup>39</sup>

In lieu of capacity availability at various market prices for most future RRs, especially wind power projects, the RRs' projected nameplate capacities of wind power projects can be adjusted to account for capacity factors associated with locational quality, such as higher average annual wind speeds.<sup>40</sup> Differences in wind speeds at various wind generator sites translate into differences of the all-in cost per unit of output (MWh). That is, wind speed and all-in per unit costs are inversely related and approximately linear.

Greater availability and deliverability of renewable resources is preferred to less. Greater deliverability may be created by transmission projects that increase "access to the high-voltage network" (Section 7.2) and that increase the "geographical diversity of the 345 kV network" (Section 7.3).

Four different generation development scenarios are considered, each one patterned after information drawn from the CAPX 2020 project in Minnesota and information provided by Wind on the Wires about potential wind power development in specific geographic locations within the upper Midwest.<sup>41</sup> Each scenario builds on an assumption about the concentration of capacity development in a particular geographic region (i.e., direction relative to the ATC service territory). Each is defined by assuming that the largest concentration of generation capacity develops in the particular geographic region identified with the scenario: Western Bias assumes the majority of generation is developed in Minnesota and North and South Dakota; Southwestern

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the costs of meeting the RPS minima. A critical input to such a study would be information on the renewable resource projects under development and planned to be in place by the 2013-2015 timeframe. The projects would need to be explicitly characterized so that they could be included in the PROMOD analysis of the Base Case and the five candidate expansion projects. These characterizations over a ten-year horizon are extremely difficult to establish. Without detailed information that would enable quantitative discrimination across the different transmission projects, the empirical analysis is unlikely to yield information that would be valuable to the decision maker. In addition, PROMOD or similar programs would have to be refined to enable the analysis to determine explicitly what the costs were of meeting the RPS under the Base Case and the candidate expansion projects.

<sup>39</sup> Even information on capacities of RRs, particularly wind power resources, available at various prices is not currently available.

<sup>40</sup> The expected economic worth of potential wind projects, as perceived by investors, is determined *inter alia* by wind and thus output, but also by the value of the output. The expected value of output, in turn, is directly related to the location (locational marginal prices) of the generators. An important aspect of wind velocity is the pattern of velocity over the course of a day and across seasons. If a potential wind generator location has a wind velocity that is strongly and positively correlated with the hourly LMPs at that location, such location will have relatively high expected wind value.

<sup>41</sup> CAPX [2004] and Soholt [2005].

Bias assumes the majority of generation is developed in Iowa; Southern Bias assumes the majority of generation is developed in Illinois; and Wisconsin Bias assumes the majority of generation is developed in Wisconsin.

Table 13 contains the generation development scenarios in nameplate capacity (MW) for wind turbines in each geographic area. Assuming the typical wind turbine is 1.5 MW, the projected capacities are converted to MWh per year of energy output to reflect capacity factors that account for variations across the regions in average annual wind speeds.<sup>42</sup> Table 14 presents the results of the conversions to MWh per year – millions of MWh per year of energy production that assumes wind turbines are the renewable resource. The ATC projects are identified by the geographic bias they tend to favor. The Lower-Voltage project is assumed to favor the Wisconsin Bias. The Byron and Paddock projects are assumed to favor the Southern Bias (Illinois). The Salem project is assumed to favor the Southwestern Bias (Iowa). The Prairie project is assumed to favor the Western Bias (Minnesota/Dakotas).

**Table 13**  
**Nameplate Capacities for Renewable Resource Scenarios in 2013**

Generation Areas	Renewable Resources Scenario (Nameplate Capacity MW)			
	Western Bias	Southwestern Bias	Southern Bias	Wisconsin Bias
Minnesota/Dakotas	2,100	1,000	500	500
Iowa	1,475	2,575	1,100	1,000
Wisconsin	500	500	1,000	2,100
Illinois	500	500	1,975	975
<b>Total</b>	<b>4,575</b>	<b>4,575</b>	<b>4,575</b>	<b>4,575</b>

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<sup>42</sup> Data on output for a 1.5 MW turbine was obtained from the Renewable Energy Research Laboratory, University of Massachusetts, Amherst, [http://www.ceere.org/rerl/publications/published/communityWindFactSheets/RERL\\_Fact\\_Sheet\\_2\\_Community\\_Wind\\_Performance.pdf](http://www.ceere.org/rerl/publications/published/communityWindFactSheets/RERL_Fact_Sheet_2_Community_Wind_Performance.pdf), accessed July 27, 2005. Data on average annual wind speeds in the regions was obtained from the American Wind Energy Association, <http://www.awea.org/faq/usresource.html> accessed July 27, 2005.

**Table 14**  
**Energy Output for Renewable Resource Scenarios in 2013**

<b>Generation Areas</b>	<b>Renewable Resources Scenario</b> <b>(MWh per year Output, millions)</b>			
	<b>Western Bias</b>	<b>Southwestern Bias</b>	<b>Southern Bias</b>	<b>Wisconsin Bias</b>
Minnesota/Dakotas	7.0	2.3	2.3	2.3
Iowa	3.1	7.8	3.1	3.1
Wisconsin	1.1	1.1	2.3	4.5
Illinois	2.2	2.2	4.5	2.2
<b>Total</b>	13.5	13.5	12.2	12.2

5.3.2. Findings

Merit scores presented in Table 15 are developed for each of the five projects and for each of the four generation scenarios under the assumption that the PSCW imposes a 10% RPS minimum that must be satisfied by 2015. Each of the four renewable resource scenarios is considered equally likely to occur. Thus the overall merit score for each ASI project, which appears in the last column of Table 14, is computed as a simple average of the individual merit scores for each generation scenario. For example, for the Western Bias scenario, the Prairie project ties the ATC grid to Minnesota and thus favors generation to the West (i.e., Minnesota/Dakotas). Therefore, Prairie is awarded a 10. All other Access Initiative projects are scored relative to Prairie by dividing the MW in the region they favor by the MW in the Minnesota/Dakotas region. Thus, for example, the Lower-Voltage project, which favors Wisconsin Bias, receives a 1.6 (1.1 divided by 7.0 multiplied by 10).

**Table 15**  
**Merit Scores for AIS Projects by Generation Scenario and Weighted Merit Scores**

<b>Transmission Project</b>	<b>Western Bias</b>	<b>Southwestern Bias</b>	<b>Southern Bias</b>	<b>Wisconsin Bias</b>	<b>Average Merit Score</b>
<b>Paddock</b>	3.2	1.5	10.0	4.9	4.9
<b>Salem</b>	4.4	10.0	7.0	6.9	7.1
<b>Lower-Voltage</b>	1.6	1.5	5.1	10.0	4.5
<b>Byron</b>	3.2	2.8	10.0	4.9	5.2
<b>Prairie</b>	10.0	3.0	5.2	5.2	5.8

## 6. BENEFITS RELATED TO ECONOMIC DEVELOPMENT

In this section, we consider three categories of benefits or costs that are related to economic development. These are:

- Local and State Economic Development
- Access to the High-Voltage Network
- Geographic Diversity of ATC's 345 kV Network

These three factors have related benefits. Local and State Economic Development refers to the positive impact of the expanded transfer capability on the level of economic activity in local communities and in Wisconsin as a whole. The second two factors refer to the positive effects on local economies and generation resources as a result of improved access to ATC's high-voltage power system.

### 6.1. Local and State Economic Development

“Local and State Economic Development” refers to the positive economic impacts that can be expected to attend transmission investment. These impacts fall into two categories: direct impacts from investment in transmission facilities; and the indirect impacts due to changes (reductions) in electricity prices in ATC's footprint.

*Direct investment impacts* are those arising from the capital and labor expenditures on transmission construction. In particular, when ATC contracts to purchase the materials for the towers, cables, and electronic equipment needed to construct new transmission lines, and hires workers to install them, some portion of those expenditures and wage payments will go to companies and workers in Wisconsin.

Because the foregoing equipment and labor expenditures will create additional rounds of economic activity, as companies supplying the purchased materials order intermediate materials from their own suppliers and as workers spend money locally, the direct investment impacts will have a multiplier effect.

Multiplier values for local economic development are specific to the event – e.g., change in output prices of a defined market segment, a change in the capital stock attributable to private investment, or a change in local government tax policy. In turn, multipliers are specific to dimension such as employment, wages, household income, and gross state product (“GSP”). An exogenous change from an equilibrium state can perturb a number of highly diffused effects across many sectors and involve changes in labor migration, population, wage rates, labor utilization, regional purchases as a share of total transactions, and imports of goods to the region of interest.

Simulation studies suggest that, depending upon the segment, type of change, and the impact of interest, multipliers can range from 1.5 to above 4.0. In addition, impact multipliers are specific to timeframe; depending upon definition, the impacts perturbed by, say, a sustained change can increase or decline through time. Generally speaking, impacts perturbed by a one-time event,

such as investment, tend to dampen out over future years. Conversely, impacts that are ongoing can lessen or expand over time.

While multiplier impacts are highly specific to circumstances, it is reasonable to assume that, as a general rule, for every \$1.00 of investment expenditure on an Access Initiative project, the project can be expected to produce \$1.50 to \$2.50 of additional gross domestic product in the ATC footprint within the year of the expenditure and the year immediately following.

*Indirect electricity price impacts* arise from the reductions in wholesale energy costs and improved reliability that are expected to accompany transmission investment. The difference between the annual expected electricity cost savings and the annualized cost of the transmission investments,<sup>43</sup> which will be recovered through retail electricity rates, represents a net cost saving to electricity customers in Wisconsin.

The benefits to retail consumers and the Wisconsin economy are of two types. First, the savings in electricity bills in Wisconsin are monies that retail consumers, Wisconsin businesses, and state and local government can use for general consumption expenditure and investment. The cost savings passed on to retail consumers have the same effect as an increase in income to consumers; and they can provide an incentive for businesses to expand or move to the state. These effects can be expected to produce a multiplier effect as discussed above. That is, residential consumers will spend a large portion of their cost savings on goods and services other than electricity, thus increasing sales of a range of businesses in the state. In addition, commercial and industrial customers can use their enhanced net revenue to finance business improvements or investments, or retain it as profit.

Second, the reduction in retail electricity bills reduces the relative costs of doing business in Wisconsin with respect to other regional economies. The result is that the Wisconsin economy can assume a path of higher economic growth over future years.

#### 6.1.1. Approach

Power system software such as PROMOD can be used to determine the savings in energy costs due to a transmission project. Similarly, the annual carrying costs for incremental transmission investment can be determined, given the estimates of the investment costs of the project options. In turn, the net impact on retail electricity bills due to a transmission project can be quantified as production cost reductions less the costs of paying for the transmission upgrades.

The tools used to determine regional economic development impacts include regional economic modeling structures, such as conceptually simple economic base or input-output (I-O) approaches. These models can be built for open and closed economies. The I-O approach involves a matrix of hundreds of coefficients that characterize the amounts of *inputs* from each business type used to produce a unit of *output* from a given industry in a particular region (*e.g.*, a state). A national I-O matrix can be calibrated to a specific regional economy on the basis of regional surveys, regional purchase coefficients, and locational quotient and supply-demand pool methods. In addition, more complete methods including the general equilibrium and the well-recognized methods developed by George Trez *et. al.* are available. This latter class of models

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<sup>43</sup> Annualized cost refers to the annual carrying charges on capital, depreciation expense, corporate income taxes, and fixed operations and maintenance expenditures which are predominantly labor costs.

is of particular interest; the *REMI Policy Insight* of Regional Economic Models Incorporated (“REMI”) is of this type and has been widely applied to broad range of regional policy issues.<sup>44</sup>

Regional economic models can often involve simulations over numerous iterations until simultaneous converged solutions are reached. The sum of the impacts across all sectors of the economy is encapsulated in a multiplier effect, as mentioned above. However, multipliers are specific to the dimension of the economy of interest, and the effects can be described in various ways, such as the impacts on employment, household income, and population. However, the net impact on the regional economy is arguably best captured by the change in GSP, which is a measure of the value added gains of the various sectors of regional economies, as reported by the Bureau of Economic Analysis for the various states. Other metrics such as the change in consumer surplus can also be estimated.<sup>45</sup>

The determination of the effects of the electricity price reductions on local and the state economies is straightforward and can be performed using the simulation models discussed above. This involves estimates of the magnitude of annual net electricity cost savings (i.e., total bill impacts) and their distribution across retail market segments and customer types. The quantification of these second-order impacts on the regional economy does not however necessarily need to involve complicated and data-intensive regional economic models. Absent a full regional economic assessment, regional impacts of investment and electricity price changes can be gauged using rather general assumptions, and then merit scored. It is this latter approach that has been taken within the immediate study.

An illustrative example might be useful. In the case of a transmission project the impacts at the outset will be driven by construction, which involves investment in physical capital, where the inputs are obtained through a combination of local purchases, outside imports, and labor. The result is an increase in overall employment, household income, and government sales tax revenues; business profit increases in some sectors but declines in others; increases in wages; and very slight declines in employment in some sectors. Nonetheless, the net result is positive for the Wisconsin economy, and this benefit partially offsets the carrying charges of later years, as reflected in retail electricity prices.

The second-order employment effects that arise from an additional construction job is, roughly, equal to 0.2 to 0.6, with the corresponding employment multiplier equal to 1.2 to 1.6. A construction project involving an increase of 75 jobs give rise to about \$8 million in increased labor income over two years as assumed. Assuming that investment purchases locally are equal to 60% of total investment, and where the facility involves capital inputs of \$200 million, the result is \$120 million over two years. The assumption of an investment multiplier with regards to gross state product equal to 1.5 results in net gains of \$180 million over two years for the economy as a whole. In total, then, net gains of some \$188 million are obtained, notwithstanding the various other second-order regional impacts that can only be gauged through the use of regional economic simulation tools that possess the necessary endogenous linkages, as reflected

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<sup>44</sup> A comprehensive technical reference is Treyz [1993].

<sup>45</sup> Calculating regional economic development impacts, however, requires care to avoid overstating the true *net* effects of the proposed project relative to the alternative base case in which the project is not undertaken. For example, the analysis should account for the extent to which the proposed investment simply replaces other investments that would otherwise have been made.

in the social accounts for the region. In short, these very basic calculations suggest that the indirect economic development impacts on Wisconsin's regional economy, which constitute real economic benefits, go a long way to offsetting the carrying charges on the investment costs of the various Access Initiative Projects.

### Analysis Findings

Table 16 presents the analyses for local economic development. The estimated impacts cover the investment effects, and future electricity price effects discounted over 7 years.

**Table 16**  
**Local Economic Benefits Attributable to the Access Initiative Projects**  
(millions of 2005 \$)

<b>Project</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Investment and Discounted Future Electric Retail Price Impacts	\$139	\$208	\$118	\$186	\$277
<b>Merit Score</b>	5.0	7.5	4.3	6.7	10.0

## 6.2. Access to the High-Voltage Network

*Access to the High-Voltage Network* describes the benefits of reduced costs of interconnection to the high-voltage network. Increased access to the 345 kV network makes it easier to site renewable resources and larger industrial loads, thus providing benefits to service providers, communities, and retail consumers in Wisconsin. In addition, the incremental costs of interconnection of new facilities for both loads and generators are reduced thus facilitating interconnection.

Through improved access to high voltage infrastructure, communities and areas are made more economically attractive and viable; transmission and accessibility to it is a key element. This is particularly important in view of how Wisconsin is limited by the sparse availability of its high-voltage facilities. Essentially, the Access Initiative projects extend the 345 kV network within southern and southwestern Wisconsin and in the lower tier of western Wisconsin, thus improving access in these regions. Also, improved accessibility to high-voltage transmission tends to expand choices by increasing the number of areas for consideration by commercial and industrial firms as potential sites for economic expansion.

Timing also plays an important role in economic development. The research and due diligence process regarding the siting and expansion of commercial and industrial facilities often proceeds with expedience. It is important for supporting infrastructure to be in place beforehand, or to be available in the short term. Insufficient infrastructure can preclude communities from

consideration as viable candidates for siting in the future. There is an advantage for local economies to have available a sufficient level of transmission infrastructure at hand.

### 6.2.1. Approach

The benefits of Access to the High-Voltage Network are challenging to assess because it is difficult to quantify the sensitivity of the siting of generation and large retail loads to improved access and to the commensurate reduction in the costs of interconnection. Knowledge of the siting sensitivity of generators, particularly renewable resources, would appear to be necessary to provide accurate estimates of benefits. Nonetheless, an understanding of siting behavior could be developed, upon which the incremental siting response to the expansion of the transmission network could be estimated.<sup>46</sup> In turn, such estimates could lead to or constitute the quantification of Access to the High-Voltage Network.

An alternative approach is also quantitative, though it does not require an analysis of siting behavior. This approach applies merit scores to a descriptive indicator of access. Under this approach, the incremental miles of 345 kV facilities are translated into merit scores by first assigning a value of 10 to the expansion option that has the most miles of new 345 kV lines, and then assigning proportionally smaller values to projects with fewer new miles.

### 6.2.2. Analysis Findings

The benefits of expanded infrastructure are shown in Table 17 below.

**Table 17**  
**Benefits of Access to the Expanded 345 kV Infrastructure**

<b>Project</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Miles of New 345 kV Lines	35	149	0	97	275
<b>Merit Score</b>	1.3	5.4	0	3.5	10.0

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<sup>46</sup> An analysis of siting sensitivity to measures of access and interconnections costs could be performed in two ways. First, a structured survey of developers, consisting of a series of questions focused on access and interconnection costs, could potentially provide a means to reveal the effects of improved access and reduced interconnection costs. Second, a database of siting experience could be assembled, where siting is described with sufficiently articulate characterizations of the observed siting events of generators and of loads. The database would need to include information describing site location and other important attributes. The database would then be assessed with statistical analysis methods. The results would be mathematical relationships that explain the response of facility siting to characteristics and attributes, with the main focus on access.

### 6.3. Geographic Diversity of the 345 kV Network

Geographic Diversity refers to benefits to various areas and communities within the ATC footprint as a result of the improved coverage by the 345 kV network. This improved coverage can give generators and large industrial loads better access to the high-voltage network, which can give rise to increased likelihood of the siting of generation facilities and larger industrial loads in relatively remote areas and communities.

Improved high-voltage coverage can also improve reliability in remote areas as well as for the entire ATC grid. Specifically, geographical diversity improves reliability by mitigation of the impacts related to common mode failure events which may cause severe consequences including cascading outages. Examples of common mode events include tornado outbreaks and ice storms; both modes encompass wide geographic areas and may impact multiple key transmission system elements if they are located close together.

The increase in geographic diversity attributable to a new 345 kV line can be represented by the distance from that line to ATC’s nearest parallel 345 kV lines. Because greater distance implies greater diversity, greater distance from existing facilities is better.

We translate miles into merit scores by first assigning a value of 10 to the project that has the most miles of distance to the nearest ATC 345 kV lines and then assigning proportionally smaller values to projects with less distance.

Table 18 shows the approximate distance from each project to the nearest ATC 345 kV line. The Lower-Voltage Reinforcement project, which includes no new 345 kV line, is assigned a distance of zero. The last row of Table 18 shows the merit scores for each of the five expansion candidates.

**Table 18**

**Approximate Distances to the Nearest ATC 345 kV Line and Resulting Merit Scores**

<b>Project</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Approximate Miles <sup>47</sup>	0	75	0	25	75
<b>Merit Score</b>	0	10.0	0	3.3	10.0

## 7. FAIRNESS AND EQUITY

“LMP comparability” refers to the level of variation among the locational marginal prices (LMPs)<sup>48</sup> of different utility service territories within ATC’s footprint. The increased transfer

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<sup>47</sup> *Ibid.*

<sup>48</sup> In any hour, LMP at a location is the change in cost that would accompany a small increase in consumption in that hour and at that location. LMPs are a means for determining the economically efficient prices for power in the short run. They are calculated by optimal power flow software based upon generator bid prices, observed locational loads, and engineering descriptions of the network topology.

capability of the ASI projects is expected to reduce LMP variation and thus improve LMP comparability. LMP comparability is measured according to the load-weighted average, over all 8,760 hours of the year 2013, of the standard deviation of each hour's average LMPs for the defined service providers, as estimated. In each hour, the standard deviation measures the variation, over five Wisconsin utilities' service territories, of the average LMPs of these service territories.<sup>49</sup> The standard deviations are calculated using weighted averages of the prices in these five service territories. To determine merit scores, we find the amount by which each candidate upgrade reduces the average standard deviation relative to that of the Base Case. We translate the reduction in the average standard deviation into merit scores by first assigning a value of 10 to the project that has the largest reduction, and then assigning proportionally smaller values to projects with smaller reductions.

Table 19 presents LMP Comparability results. The first row shows the average standard deviation ("ASD") of the LMPs for each case relative to the Base Case. The second row shows the reduction in the average standard deviation for each change case. The Byron upgrade, which has the largest reduction, is assigned a merit value of 10.0. The other upgrades are assigned lower values in proportion to the relative sizes of their reductions.

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<sup>49</sup> The service territories are Madison Gas and Electric ("MG&E"), Upper Peninsula Power Company ("UPPCO"), Wisconsin Electric Power ("WEP"), Wisconsin Power and Light ("WP&L"), and Wisconsin Public Service Company ("WPS").

The weighted average standard deviation (ASD) for the year of the LMPs for project assessment case k is calculated as follows. First, given the load  $L_{hu}$  for each hour h and each utility service territory u, calculate the load weight for each service territory as:

$$W_{hu} = L_{hu} / \sum_v L_{hv}$$

where  $W_{hu}$  is the weight applicable to hour h in service territory u, and v is a dummy index for service territories. Note that, in each hour, the weights  $W_{hu}$  sum to one. Second, calculate the load-weighted average LMP in each hour as

$$\overline{LMP}_{hk} = \sum_u W_{hu} * LMP_{huk}$$

where  $\overline{LMP}_{hk}$  is the weighted average LMP for hour h for project assessment case k, and  $LMP_{huk}$  is the LMP for hour h in service territory u for project assessment case k. Third, calculate the standard deviation of LMPs in each hour as:

$$SD_{hk} = \sqrt{\sum_u W_{hu} * (LMP_{huk} - \overline{LMP}_{hk})^2}$$

where  $SD_{hk}$  is the standard deviation for hour h for project assessment case k. Finally, the annual average standard deviation is a load-weighted average of the standard deviations of each of the hours in the year:

$$ASD_k = \sum_h \left( SD_{hk} \sum_u L_{hu} \right) / \sum_h \sum_u L_{hu}$$

where  $ASD_k$  is the annual average standard deviation for project assessment case k.

**Table 19**  
**LMP Comparability, Load-Weighted Standard Deviation of LMP Differences**  
(\$ per MWh)

	<b>Base Case</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
Average S.D.	0.837	0.672	0.609	0.641	0.600	0.745
Reduction in Average S.D.		0.164	0.228	0.196	0.237	0.092
<b>Merit Score</b>		6.9	9.6	8.3	10.0	3.9

## 8. SUMMARY OF RESULTS

Table 20 summarizes the merit scores of the identified Other Factors associated with the five ATC Access Initiative projects.

**Table 20**  
**Summary of Other Factors, Access Initiative Projects**

<b>Other Factor Group</b>	<b>Other Factor Category</b>	<b>Paddock</b>	<b>Salem</b>	<b>Lower-Voltage</b>	<b>Byron</b>	<b>Prairie</b>
<i>Reduced Operating Risk</i>	Fuel Diversity	9.6	8.2	9.7	9.3	10.0
<i>Reliability Benefits</i>	Technology Diversity	8.6	10.0	8.3	8.8	0
	Reduced EUE	3.0	10.0	1.6	9.9	1.4
	Improved System Performance	8.9	9.8	0.2	10.0	4.2
<i>Power System Externalities</i>	Benefits to Neighboring Systems	8.0	8.0	2.0	8.0	10.0
	Enhanced Value to Other Projects	0	10.0	0	0	0
	Transfer Capability	6.1	10.0	8.8	8.3	8.4
<i>Environmental Benefits and Costs</i>	Societal Impacts	9.5	9.6	10.0	6.5	0.0
	Access to Renewable Resources	4.9	7.1	4.5	5.2	5.8

<i>Economic Development</i>	Local & State Economic Development	5.0	7.5	4.3	6.7	10.0
	Access to HV Infrastructure	1.3	5.4	0	3.5	10.0
	Geographic Diversity	0.0	10.0	0	3.3	10.0
<i>Fairness and Equity Aspects</i>	LMP Comparability	6.9	9.6	8.3	10.0	3.9

## APPENDIX

### Load

Table A-1 shows annual class loads for 2003. Based on recent load forecasts provided by the distribution companies in the ATC service territory, the average compounded peak demand growth rate within ATC's service territory for the period 2005 through 2014 is 3.1% per annum.<sup>50</sup> Applying this 3.1% rate to energy consumption from 2003 to 2013 yields the load forecasts shown for 2013 at the bottom of Table A-1.

**Table A-1<sup>51</sup>**  
**Annual Loads by Class in 2003 (GWh)**

Company Name	Residential	Commercial	Industrial	Total
Adams-Columbia Electric Coop	266	82	67	415
Alger Delta Coop Electric Association	48	13	0	61
Central Wisconsin Electric Coop	71	17	2	90
Cloverland Electric Coop	120	49	33	201
Edison Sault Electric Co.	170	295	200	666
Madison Gas & Electric Co.	801	1,981	299	3,081
Northern States Power Co. Wisconsin	1,884	1,126	2,851	5,861
Ontonagon County Rural Electric Association	21	2	4	27
Rock County Electric Coop Association	65	14	0	80
South Beloit Water, Gas & Electric Co.	71	45	88	204
Upper Peninsula Power Co.	277	258	211	746
Wisconsin Electric Power Co.	7,929	8,664	11,202	27,795
Wisconsin Power & Light Co.	3,339	2,189	4,507	10,035
Wisconsin Public Service Corp.	3,037	3,529	4,135	10,701
Totals (2003)	18,100	18,265	23,599	59,964
Inferred Class Energy Sales, 2013	24,634	24,858	32,118	81,610

<sup>50</sup> Population and economic growth in Milwaukee, Madison, Green Bay, and along certain interstate corridors is primarily responsible for the growth in electricity demand.

<sup>51</sup> Load data for municipal electric utilities was not available.

## **Generation**

Future generation incorporated into the Access Initiative analysis includes the following new known and expected generators as well as generation reratings:

Riverside (2004)	603 MW
Butler Ridge (2006)	11 MW
Fox Energy (2006)	603 MW
Lakefront No. 9 (2006)	59 MW
Point Beach rerating (2006)	16 MW
Blue Sky (2006)	16 MW
Green Field (2006)	16 MW
Forward Energy Center (2006)	40 MW
Port Washington (2008)	545 MW
Weston 4 (2008)	519 MW
Elm Road 1 (2009)	615 MW
Elm Road 2 (2010)	615 MW

Also, an additional unit at the Elm Road site (Unit 3) is incorporated into the analyses as a sensitivity case.

## **Major Transmission Topology Changes**

The anticipated major transmission projects, as incorporated into the Access Initiative analyses include the following projects:

- 2005: Rebuild and conversion of one Hiawatha-Indian Lake 69 kV circuit to double circuit.  
Conversion of Menominee-Rosebush 69 kV line to 138 kV  
Construct double-circuit 138 kV line from Forest Junction/Charter Steel to Howards Grove
- 2006: Construction Gardner Park-Stone Lake 345 kV line  
Build new breaker and a half 345/138 kV substation in North Madison  
Construct 345/138 kV switchyard at a new Werner West SS including several elements  
Construct North Appleton 345 kV double breaker bus configuration
- 2007: Relocate Cedar substation at North Lake

- Construct a Jefferson-Lake Mills-Stony Brook 138 kV line
- Rebuild/convert Pulliam-Pioneer 69 kV line to 138 kV
- Construct a new Lannon Junction substation at Granville-Arcadian 345 kV
- 2008: Construct Stone Lake-Arrowhead 345 kV line
- Rebuild/convert Conover-Iron River-Plains 69 kV to 138 kV
- 2009: Construct Gardner Park-Central Wisconsin 345 kV line
- Construct Central Wisconsin 345 kV substation
- Construct Monroe County-Council Creek 161 kV line
- Construct Morgan-Werner West 345 kV line
- Expand Oak Creek 345 kV switchyard to interconnect a new generator
- Construct Rockdale-Concord 345 kV line
- 2010: Convert Hillman to Eden 69 kV to 138 kV
- Convert Waunakee-Blount 69 kV line to 138 kV
- Install second 500 MVA 345/138 kV transformer at Oak Creek
- Construct a Concord-Bark River 345 kV line
- 2011: Construct 345 kV line from Rockdale to West Middleton
- 2012: Rebuild Blaney Park-Munising 69 kV to 138 kV
- Rebuilt and convert West Middleton-Spring Green 69 kV line to 138 kV
- Construct 69 kV line Eden through Muscoda to Richland Center
- 2013: Rebuild/convert Chalk Hills-Chandler 69 kV to 138 kV operation
- Construct new 138 kV line from Twin Lakes to Spring Valley
- Expand Oak Creek 345 kV switchyard to interconnect with three new generators plus one new 345 kV line
- Construct a 345/138 kV switchyard at Brookdale to accommodate two 345 kV lines and other elements
- Construct an Oak Creek-Brookdale 345 kV line
- Construct a Brookdale-Granville 345 kV line converting/reconductoring 5.6 miles 138 kV, rebuilding 7 miles of 138 kV double-circuit, and converting/reconductoring 3 miles 138 kV on existing 345 kV structures

## Wind Speeds for Wind Generators

Table A-2

Annual Avg. Wind Speed at Hub Height	Estimated Capacity Factor	Estimated MWh/Yr per 1.5 - 1.8 MW Turbine	Midpoint of Est. MWh/yr per 1.5-1.8 MW Turbine	Midpoint Est. Capacity Factor
6.0 m/s	22% - 25%	3,320 – 3,500	0.00341	23.5
6.5 m/s	27% - 30%	3,920 – 4,190	4055	28.5
7.0 m/s	31% - 34%	4,500 – 4,880	0.00469	32.5
7.5 m/s	35% - 39%	5,150 – 5,540	5350	37

Source: Renewable Energy Research Laboratory, University of Massachusetts, Amherst, [http://www.ceere.org/rerl/publications/published/communityWindFactSheets/RERL\\_Fact\\_Sheet\\_2\\_Community\\_Wind\\_Performance.pdf](http://www.ceere.org/rerl/publications/published/communityWindFactSheets/RERL_Fact_Sheet_2_Community_Wind_Performance.pdf)

## Regional Wind Speeds

Table A-3

Region	Speed (m/s)	Midpoint
Iowa	6.4-7.5	7.0
Wisconsin	5.6-6.4	6.0
Minnesota	6.4-7.5	7.0
N/S Dakota	6.4-7.5	7.0
Illinois	5.6-6.4	6.0

## Outage Costs

Most North American research on outage costs was conducted in the 1980s, often on behalf of the Electric Power Research Institute (EPRI) or individual utilities. Subsequently, interest in outage cost studies in North America seems to have waned while interest overseas has grown.

The literature provides outage cost estimates that are reported in a wide variety of units, such as costs per outage, costs by length of outage, and costs per unit of unserved energy. In addition, these results are based on the application of a wide variety of methods. These methods can be broadly cast into three categories: proxy methods, stated preference methods, and revealed preference methods.

- *Proxy methods* use data on directly observable variables to approximate outage costs. Proxy estimates of outage costs can be based on ratios of output to electricity use, values

of inputs, prices of electricity, and the cost of purchasing and operating back-up power sources.

- *Stated preference methods* rely on respondents' self-reports on the costs of outages. For residential customers, stated preference surveys typically ask the customer to reveal either willingness-to-pay to avoid outages, or willingness-to-accept compensation for reductions in reliability. On the commercial and industrial side, stated preference data are typically collected from surveys asking respondents to reveal the impacts of an outage on costs and revenues.<sup>52</sup>
- *Revealed preference* methods use observations of actual behavior to make inferences about the value of the outage. For example, by observing purchases of back-up equipment, one might be able to make inferences about the value of outages. Likewise, if consumers of electricity were allowed to select a preferred combination of price and expected outages from their electricity supplier, observations of these choices would allow inferences about the value of service and, hence, the cost of outages. Finally, observation of how power users choose among interruptible and/or curtailable rates could form the basis for inferences about outage costs.

Economists frequently regard inferences based on revealed preference data as providing the most valid measures of outage costs. The reason is that revealed preferences show what customers really do when they have real money at stake.

Economists are more concerned about the validity of stated preference methods. The concern is that stated preference data are potentially subject to a number of biases. For example, if a respondent to a stated preference survey believes that his/her responses will affect the quality, quantity, or price of the good being studied (in this case service reliability), this belief may induce the respondent to systematically misstate preferences. The general concern is that since real money is not at stake in stated preference surveys, respondents will tend to overstate their preferences. Thus, it is often expected that values inferred from stated behavior data are likely to exceed values inferred from revealed preference methods.

While the reliance on stated preference methods raises the question of possible bias, the empirical evidence across many studies suggests that, on average, the magnitude of this bias may not be large. Empirical studies however, do not necessarily show that bias and overstatement of values are necessarily present in stated preference studies. Indeed, a study comparing revealed preference and stated preference values found that, on average, stated preference values were slightly *lower* than revealed preference values.<sup>53</sup> This suggests that well designed stated preference studies *can* produce results consistent with results derived from revealed preference studies.

Results based on proxy methods can be regarded as only approximations to the true underlying outage costs. Because the U.S. electric system generally exhibits a high degree of reliability, the

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<sup>52</sup> Some might quibble with characterizing this commercial and industrial approach as a stated preference method. This argument is based on the fact that businesses give a self-report on what they would actually experience during an outage. Thus, the method might be better classified as self-report of revealed preference data. Since data collected do not reflect observations of actual behavior, we classify it as a stated preference method.

<sup>53</sup>Carson *et al* [1996].

context for developing revealed preference studies has been very limited; so few studies have actually employed this method. Consequently, the majority of studies have been based on stated preference methods.

The outage cost figures that appear in the text are derived from Caves, Herriges, and Windle [1989, 1992], Hartman, Doane, and Woo [1990], Sanghvi [1990], Tollefson [1993], and Woo and Pupp [1992]. The foregoing studies cite a plethora of results from yet other studies. Our outage cost figures rely upon these other studies as well. These other studies are Allan and Billinton [1993], Ashraf and Sabih [1993], Beenstock and Goldin [1997], Beenstock, Goldin, and Haitovsky [1997], Carson, Flores, Martin, and Wright [1996], Caves, Herriges, and Windle [1990], Champ, Bishop, Brown, and McCollum [1997], Dalton, Garrison, and Fallon [1996], Grosfeld-Nir, and A. Tishler [1992], Kariuki, and Allan [1996], Matsukawa and Fujii [1994], Serra and Fierro [1997], Subramaniam, Wacker, and Billinton [1993], Subramaniam, Billinton, and Wacker [1993], Sullivan, Vardell, and Johnson [1997], Sullivan *et al.* [1996], and Tishler [1993].

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