

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

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**Docket No. RM15-\_\_-000**

**PETITION FOR RULEMAKING  
OF THE AMERICAN WIND ENERGY ASSOCIATION  
TO REVISE GENERATOR  
INTERCONNECTION RULES AND PROCEDURES**

Pursuant to sections 205 and 206 of the Federal Power Act (“FPA”)<sup>1</sup> and section 385.207(a)(4)<sup>2</sup> of the Federal Energy Regulatory Commission’s (“FERC” or “Commission”) regulations, the American Wind Energy Association (hereinafter referred to as “Petitioner” or “AWEA”)<sup>3</sup> respectfully petitions the Commission to conduct a rulemaking to revise provisions of its *pro forma* Large Generator Interconnection Procedures (“GIP”) and *pro forma* Large Generator Interconnection Agreement (“GIA”). For the reasons set forth herein, the time is ripe for the Commission to make certain regulatory and policy changes to interconnection procedures in order to remedy unduly discriminatory and unreasonable barriers to generator market access that inhibit the development of electric generation to meet the growing needs of electricity customers, and to facilitate the current dramatic transformation of the electric generation system (driven, in part, by Federal and State policies) in a timely, reliable and cost-effective manner.

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<sup>1</sup> 16 U.S.C. § 824(d)-(e) (2012). The Commission is charged with the responsibility under sections 205 and 206 of the FPA to ensure that the rates, charges, and classifications of a public utility are just and reasonable and not unduly discriminatory or preferential.

<sup>2</sup> 18 C.F.R. § 385.207 (2014).

<sup>3</sup> AWEA is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the United States. AWEA’s members include wind energy facility developers, owners and operators, construction contractors, turbine manufacturers, component suppliers, financiers, researchers, utilities, marketers, customers, and their advocates.

## I. EXECUTIVE SUMMARY

Interconnection rules play a crucial role in helping bring much-needed generation into the market at just and reasonable costs. Relatively unencumbered entry into the market is a component of competitive markets and necessary for consumers to reap the benefits of cost-effective generation of energy. However, the current interconnection process, which has imbedded unjust and unreasonable and unduly discriminatory delays, costs, rates, terms and conditions, imposes barriers to the development of needed new generation resources.

Although the Commission's previous generator interconnection reforms had generally positive results, more than a decade has passed since the Commission last looked holistically<sup>4</sup> at whether interconnection procedures remain consistent with its statutory mandates. In those intervening years, not surprisingly, many circumstances have changed, in ways that could not have been foreseen years ago by the Commission. As a result, various aspects of GIPs and GIAs are simply out of date in comparison to current market conditions and do not ensure that the generation interconnection process is just, reasonable, and not unduly discriminatory or preferential.

Order No. 2003 certainly helped increase the predictability in the interconnection process and reduced opportunities for incumbent transmission owners to discriminate. Further, many of the changes to interconnection procedures in recent years have led to positive outcomes in some regions, such as faster processing of interconnection requests. But, in the intervening years since

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<sup>4</sup> Specifically, it has been twelve years since the Commission issued Order No. 2003, which addressed discrimination against independent developers. *Standardization of Generator Interconnection Agreements and Procedures*, ("Order No. 2003"), FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, ("Order No. 2003-A"), FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, ("Order No. 2003-B"), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, ("Order No. 2003-C"), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230, (Feb. 25, 2008). And, it has been seven years since the Commission focused on interconnection queuing practices. *Order on Technical Conference*, 122 FERC ¶ 61,252 (2008) ("Queue Order").

these reform efforts, Transmission Providers<sup>5</sup> have changed their GIPs in a myriad of ways that, although occasionally providing limited benefits in some regions,<sup>6</sup> across the board have not solved, and have even exacerbated, problems encountered by Interconnection Customers. More importantly, many other key barriers facing Interconnection Customers have emerged in those years and some have simply never been addressed.

Today, requests for interconnection frequently result in complex, time consuming technical disputes about interconnection feasibility, cost, and cost responsibility. This delay naturally undermines the ability of new generators to compete. Delays and inaccuracies in individual interconnection studies and lack of accurate and timely information for Interconnection Customers to take into account in making decisions, for example, can not only stall interconnection but can result in viable projects never being developed.

Without regulatory changes to address these barriers to generator market entry, Interconnection Customers will not have the regulatory certainty (*e.g.*, clear expectations and firm timelines) required to enable generation facilities to move through the interconnection process in a just and reasonable and non-discriminatory manner. If further reform of the *pro forma* GIP and GIA is undertaken to provide a clear and predictable pathway for market entry for new generation, it will reduce interconnection costs and thereby lower costs of new generation for the benefit of consumers, result in the processing of requests in a timely manner, provide the

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<sup>5</sup> Unless otherwise specified, capitalized terms in this Petition have the meaning given to them in the Commission's *pro forma* GIPs. AWEA recognizes numerous other terms are likewise defined in the GIPs, but usage here as capitalized terms is not essential for purpose of the Petition. Non-capitalized terms are to be interpreted based on general industry usage, such as interconnection request and transmission owner.

<sup>6</sup> Positive improvements in some, but not all, regions include shorter stated study timelines, more flexibility to allow Interconnection Customers to choose when they are ready to move forward to the final study phases, options for customers to enter into interim or provisional interconnection agreements to get on-line earlier, and creation of mechanisms by which Interconnection Customers share the costs of network upgrades with later-queued generators. However, although positive in some respects, many of these changes also have increased the risks incurred by Interconnection Customers.

certainty needed to encourage investment for the development of economic generation, and ultimately allow for the successful development of new generation facilities needed to ensure system reliability and keep pace with the increase in demand growth and planned retirements of a significant number of older, inefficient generators. In short, properly revised interconnection procedures for all jurisdictional Transmission Providers will minimize opportunities for undue discrimination and unjust and unreasonable processes and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.

The key reforms requested herein relate to the certainty of regulatory and administrative treatment in the interconnection process, which is a critical factor to support new generation facilities. Ultimately, Petitioner arrived at proposals that fall into four general categories to enhance this certainty: (1) enhancing certainty in the study/restudy process; (2) providing more transparency in the interconnection process; (3) creating more certainty on network upgrade costs; and (4) ensuring more accountability if a Transmission Provider fails to perform properly its duties. Specifically, Petitioner proposes the following changes to the *pro forma* GIP and GIA:<sup>7</sup>

**A. Reforms to improve certainty in the study/restudy process:**

- i. Require timely and accurate studies and restudies.
- ii. Create an enforceable obligation to provide timely study/restudy results.
- iii. Limit restudies to one per year or provide cost-certainty that would eliminate the need for restudies.
- iv. Require the inclusion in studies, and the GIA, of only those contingent facilities that are shown to be electrically relevant to an Interconnection Customer's project.
- v. Require the Transmission Provider to provide cost estimate information earlier in the study process.

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<sup>7</sup> Transmission Providers would then revise their GIPs and GIA to conform to the revised rules, or as applicable to regional transmission organizations ("RTOs"), explain why their own practices are consistent with or superior to the *pro forma* GIPs and GIA.

- vi. Require the Transmission Provider to list standardized study costs and allow recovery of those costs up to a stated cost accuracy margin listed in its GIP absent demonstrated extraordinary circumstances beyond the Transmission Provider's control.

**B. Reforms to improve transparency in the interconnection process:**

- i. Require the Transmission Provider to provide more information about its interconnection study assumptions.
- ii. Require curtailment risk information to be provided on a Transmission Provider's website and in interconnection studies.
- iii. Allow an Interconnection Customer to use its interconnection capacity through two or more phases, and in two or more GIAs, and provide for full reimbursement if the capacity is terminated and used by another customer.

**C. Reforms to improve certainty of network upgrade costs:**

- i. Require the costs for interconnection facilities and network upgrades to be capped at stated accuracy margins absent demonstrated extraordinary circumstances beyond the Transmission Provider's control.
- ii. Allow a Transmission Provider to fund network upgrades (self-funding) only if agreed to by the Interconnection Customer.
- iii. Require compensation for network upgrades that benefit later Interconnection Customers and network users.
- iv. Require the Transmission Provider to follow a consistent process and cost methodology for the Interconnection Customer to fund additional, restorative network upgrades.

**D. Reforms to improve accountability in the interconnection process:**

- i. Require the Transmission Provider to pay liquidated damages to the Interconnection Customer when it fails to provide timely or accurate interconnection studies.

The Petitioner respectfully requests that the Commission conduct a notice of proposed rulemaking to revise provisions of its *pro forma* GIP and GIA consistent with these recommendations. AWEA is mindful that the Commission has often first initiated a technical conference to further consider issues set forth in a petition before issuing a proposed rulemaking. To the extent that the Commission thinks such a conference would aid its decision-making process in this proceeding, the Petitioner supports such an approach.

## II. COMMUNICATIONS

All communications with AWEA regarding this matter should be addressed to:

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## III. BACKGROUND

### A. Past Interconnection Reform Efforts

Several years after the Commission issued Order No. 888 to ensure non-discriminatory transmission service under an open access transmission tariff (“OATT”), the Commission embarked on a process to ensure that generators could similarly obtain interconnection service on non-discriminatory terms. In an environment of increased development of generation by new market participants, the Commission recognized that interconnection is a critical component of open access transmission service and, therefore, a Transmission Provider is required to offer comparable interconnection service.<sup>8</sup> The Commission further concluded that interconnection service is an integral element of an overall regulatory regime intended to ensure that the

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<sup>8</sup> *Tennessee Power Company*, 90 FERC ¶ 61,238 at P 9 (2002).

transition to competitive markets benefits consumers, stating that: “Balanced market rules and sufficient infrastructure are essential for achieving power markets that will provide customers with reasonably priced and reliable service.”<sup>9</sup>

In light of the Commission’s belief in the importance of interconnection service for markets across the country, the Commission issued the landmark Order No. 2003, concluding that standardizing interconnection procedures “will minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.”<sup>10</sup> The Commission further explained: “Interconnection plays a crucial role in bringing much-needed generation into the market to meet the growing needs of electricity customers [and]... relatively unencumbered entry into the market is necessary for competitive markets.”<sup>11</sup> The Commission also noted that despite the critical importance of interconnection service, “requests for interconnection frequently result in complex, time consuming technical disputes about interconnection feasibility, cost, and cost responsibility. This delay undermines the ability of generators to compete in the market and provides an unfair advantage to utilities that own both transmission and generation facilities.”<sup>12</sup> The Commission concluded that standardizing interconnection procedures “will minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.”<sup>13</sup>

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<sup>9</sup> Order No. 2003 at P 5.

<sup>10</sup> *Id.* at P 11.

<sup>11</sup> *Id.*

<sup>12</sup> *Id.* When the Commission issued Order No. 2003, the Commission recognized that RTOs and Independent System Operators (“ISOs”) (hereinafter, jointly “RTOs”) have different operating characteristics and are “less likely to act in [an unduly] discriminatory manner than a Transmission Provider that is also a market participant,” and allowed them to seek “independent entity variations” from Order No. 2003’s pricing and non-pricing provisions. *Id.* at P 548, 827.

<sup>13</sup> *Id.* at 11.

Order No. 2003 was issued during a time of increased growth of variable energy resources, and the order likely helped continue this growth. Developers submitted numerous interconnection applications, interconnection queues grew larger, and due to this large influx, queue processing became slower. Within several years, the Commission addressed the resulting delays in processing of interconnection queues in the Queue Order.

In response, several RTOs filed proposals with the Commission to revise their GIPs. These proposals were multi-faceted, but focused largely on attempting to reduce the size of the queues based on increasing the obligations of Interconnection Customers both through deposits and by requiring them to demonstrate project progress. These proposals were typically accepted with some modifications by the Commission.<sup>14</sup>

## **B. The Generator Interconnection Process**

Generation development involves numerous processes – siting, permitting, turbine acquisition, financing, interconnection, transmission rights, and marketing and sale of the project’s output – and each affects the other. Generation developers have a variety of tools to manage risks and costs associated with many of these factors. However, generation interconnection is somewhat of an outlier because it is typically the part of the project development process with the greatest uncertainty and risk of delay for developers and the area in which developers often have the fewest opportunities to manage and control those risks and

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<sup>14</sup> See, e.g., *Midwest Indep. Transmission Sys. Operator, Inc.*, 124 FERC ¶ 61,183 (2008) (making Interconnection Customer milestones more rigorous and allowing projects to proceed based on readiness, rather than solely on queue position); *Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,233 (2012) (expanding “first-ready, first-served” concept and increasing Interconnection Customer payment obligations); *Southwest Power Pool, Inc.*, 128 FERC ¶ 61,114 (2009) (transitioning to “first-ready, first-served” queue processing and increasing deposit amounts and project readiness milestones); *Southwest Power Pool, Inc.*, 147 FERC ¶ 61,201 (2014) (revising queue priority formation and increasing payments and other obligations of Interconnection Customers); *Cal. Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,031 (2008) (obtaining waiver of interconnection procedures to accelerate queue processing); *Cal. Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,292 (2008) (better integrating the interconnection process with the transmission planning process, and increasing and accelerating the financial commitments required to participate in the interconnection process); *ISO New England, Inc.*, 126 FERC ¶ 61,080 (2009) (increasing financial deposits required in interconnection processing).



issues. As the Commission has made clear, interconnection is one of the key elements that must fit together for project development to be successful:

[T]he interconnection-related study process may be the only reliable vehicle a customer has to evaluate the merits of different interconnection points and configurations. Thus, it is critical that reforms applicable to future and early-stage existing interconnection requests provide customers with enough flexibility and information to respond to business uncertainties.<sup>15</sup>

To obtain interconnection to the grid, an Interconnection Customer must submit an interconnection request to a Transmission Provider, and then wait for several rounds of interconnection studies and often restudies to be completed, which can take several years. Successful navigation of this process depends on receiving timely and accurate information about the cost and timing of the Transmission Provider's interconnection facilities and network upgrades. Once the developer has an adequate picture of development costs and timelines, including the interconnection elements, other capital costs, and expected revenues from the project, it may then choose to either proceed with or cancel development of the project in light of known interconnection costs. If the developer proceeds and signs the GIA, it must then wait for the interconnection facilities and network upgrades to be built, and only then can it obtain full interconnection service. The wait for upgrades to be built by the transmission owner can last years.

Although many of the changes to interconnection procedures have allowed for improvements in the processing of interconnection requests (such as accelerating queue processing), other key issues facing Interconnection Customers have not been resolved, including the delay and inaccuracy of individual interconnection studies, and lack of accurate and timely information for Interconnection Customers to take into account in making their

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<sup>15</sup> Queue Order at P 14.

decisions. This can be partly attributed to the fact that, although most of the various interconnection reforms in recent years have been achieved by typically putting a larger burden on Interconnection Customers (*e.g.*, larger deposits some of which are non-refundable), no commensurate burden has been placed on Transmission Providers to produce, among other things, timely and accurate study results.

The ability to accurately complete study requests on time and in a relatively accurate manner is entirely within the control of the Transmission Provider. However, if studies are delayed or produce inaccurate results, then the Interconnection Customer's commercial expectations can be thwarted, even though it has no control over the process. An unnecessary and unexpected delay in completion of the studies can affect project development in numerous ways. It may jeopardize a developer's financing, resulting in increased financing costs or even project cancellation. The land leases or options that developers must secure with landowners have limited time frames and may also expire or be costly to extend. A developer also needs accurate and timely interconnection pricing information in order to participate in a utility's Request for Proposal ("RFP") or to initiate any discussion with a possible off-taker. A developer's ability to price a Power Purchase Agreement ("PPA") is hampered by not knowing its actual interconnection costs. In addition, if the Transmission Provider later seeks to revise the estimated cost or scope of network upgrades assigned to a project to correct for previous errors, then generation projects may be saddled with previously unanticipated costs. All of this, in turn, translates to higher costs to consumers.

Petitioner contends that these problems are likely the result of the fact that Transmission Providers do not have any material performance requirements under their GIPs. These concerns about delayed and inaccurate study results are not theoretical, as projects have been stalled, or

even cancelled, across the country, due to these issues. In addition, although the need for the revisions sought herein reflect the experience of Petitioner's members, improvement to the interconnection process will benefit all types of generating facilities in their interconnections to the grid and, in turn, facilitate timely and cost-effective development of new generation in the United States.

### **C. Need for New Generation Development**

The electric power industry continues to be in fundamental transformation, moving from “dirtier” sources of electric energy to “cleaner” ones. As a consequence, the fuel mix of the United States power system is changing rapidly. Against this backdrop, in June 2014, the U.S. Environmental Protection Agency (“EPA”) released its proposed Clean Power Plan (“CPP”) as a means of implementing section 111(d) of the Clean Air Act to regulate carbon dioxide (“CO<sub>2</sub>”) emissions from existing fossil fuel electric generation plants.<sup>16</sup> Recently, the Commission held a series of technical conferences to explore its role for dealing with any potential impacts the CPP may have on electric reliability.<sup>17</sup>

The CPP, as well as other influences, will likely result in greater retirements of coal-fired generators and expanded use of generation using natural gas and renewable energy. The Energy Information Administration (“EIA”) recently released projections that the CPP would spur a quick wave of coal plant retirements – 90 gigawatts between 2014 and 2040.<sup>18</sup> Most of the power plant retirements would happen by 2020, when the first requirements for emissions

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<sup>16</sup> See *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Notice of Proposed Rulemaking, 79 Fed. Reg. 34,830 (June 18, 2014).

<sup>17</sup> *Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure*, Notice Of Technical Conferences, Docket No. AD15-4-000, Dec. 9, 2014.

<sup>18</sup> U.S. Energy Information Administration, *Analysis of the Impacts of the Clean Power Plan*, May 2015, available at: <http://www.eia.gov/analysis/requests/powerplants/cleanplan/pdf/powerplant.pdf> (“Analysis of the Impact of the Clean Power Plan”).

reductions from the CPP would begin. The analysis shows the rule would shift generation away from baseload coal, nuclear and hydropower and toward natural gas and renewables.<sup>19</sup> For example, in the Mid-Atlantic region, under EIA's main case for examining the CPP, real-time fuel, such as natural gas-fired generation, would increase from 27% in 2013 to 46% in 2030 and renewable energy would increase from 2% to 7% in these same time frames..<sup>20</sup>

Those shifts are what some have attempted to claim might cause electric reliability concerns. But, according to EIA, “[t]here are several ways to mitigate potential issues that may arise from increased reliance on generation using real-time fuels and intermittent renewable generation.”<sup>21</sup> Indeed, these changes, without a doubt, can be accommodated, particularly with advance planning to address the changing characteristics of the system. Petitioner contends that generation interconnection reform represents an important area where the FERC could carry out its responsibilities cognizant of EPA action and help ensure reforms to organized electric markets are carried out to accommodate CPP implementation, achieving its environmental benefits at lower cost to consumers and allowing the compliance timeline established under the CPP to be met. Specifically, this would enhance states' ability to comply with their required carbon reduction targets by getting cleaner electric energy resources in place to meet the demand required to implement the CPP.

#### **D. Need for Generator Interconnection Reform**

Now, twelve years after Order No. 2003 and seven years after the Queue Order, AWEA proposes various measures to reform the timeliness, accuracy, uniformity, and transparency of the interconnection process, and to encourage the Commission to evaluate the diversity in

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<sup>19</sup> *Id.* at 16, 34.

<sup>20</sup> *Id.* at 61.

<sup>21</sup> *Id.* at 60.

interconnection rules now in effect<sup>22</sup> and require more wide-spread use of best practices adopted in various regions to address these issues. The current *pro forma* GIP and GIA allow for unjust, unreasonable and unduly discriminatory delays, costs, terms and conditions and lack of transparency that erect barriers to getting generation interconnected in a timely and cost-effective basis.

The need for interconnection reform is all the more critical given aforementioned current and impending changes to the generation mix in this nation. Reforms would lower barriers to generator interconnection and help ensure reliability as the electric generation system undergoes a transformation. In short, the interconnection reforms proposed herein will provide for necessary market changes, through more efficient GIPs and GIA provisions, that will foster development of needed new generation that is reasonably priced and provides reliable service for consumers.

#### **IV. PETITION**

The need for the revisions addressed herein comes from AWEA members' direct experience with seeking interconnection service from RTOs and other Transmission Providers throughout the United States.<sup>23</sup> Members have canceled generation projects or incurred higher than reasonably expected costs to construct generating projects because of the delay, uncertainty and lack of transparency in current GIPs.

These problems often have not resulted in the aggrieved developer filing a complaint, under section 206 of the FPA with the Commission, as this is often an inadequate remedy. The

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<sup>22</sup> Although RTOs have used the independent entity variation standard to propose some needed changes to their GIPs, the requirements and processes across the United States have becoming increasingly distinct and some have only served to cause further delays and increased costs for Interconnection Customers.

<sup>23</sup> The reforms AWEA proposes herein do not result only from dealing with RTOs. The same problems can and do result in non-RTO markets, hence the need for nationwide reform. The vast majority of new generation, however, is developed in RTO markets, which is why Petitioner provides frequent references to the RTOs and their varying practices.

Interconnection Customer is typically working under tight project development timelines; therefore, preparing and filing a complaint and waiting for the Commission's decision is often not a viable course of action. Even if time is not limited, litigating and developing a project at the same time is a difficult scenario that can cause a project to languish and the working relationship with the Transmission Provider to worsen.<sup>24</sup> The Commission recognized this in Order No. 2003, noting that resolving such disputes through complaints is "an inadequate and inefficient means to address interconnection issues."<sup>25</sup> The same conclusion applies today, as reforming GIPs through individual complaints will not lead to the type of broad and inclusive discussion on the need for reform. A rulemaking is the optimal means for creating the widespread discussion needed to achieve solutions to these issues.

**A. Reforms to Improve Certainty in the Study and Restudy Process**

**i. The Transmission Provider Should be Required to Provide Interconnection Study and Restudy Results by the Dates Listed in the GIPs**

In recent years, Transmission Providers throughout the United States have revised their GIPs for the specific purpose of clearing out the backlog of pending interconnection study requests and improving service to Interconnection Customers. In response, Interconnection Customers have had to choose whether to withdraw projects that may have uncertain commercial prospects or pay higher study and processing fees. As a result, many projects have been withdrawn, while others considered to have better commercial prospects remained. Following these OATT changes, some RTOs have reported that the interconnection queue has shortened

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<sup>24</sup> For these reasons, AWEA also does not discuss the details of non-public interconnection disputes of any of its members in this Petition.

<sup>25</sup> Order No. 2003 at P 10.

and that study times have been reduced.<sup>26</sup> With fewer projects in the queue and increased use of cluster studies, Interconnection Customers expected that interconnection study timeliness would improve – not an unreasonable expectation in light of the increased burdens placed on them in complying with the new GIP requirements. But contrary to this expectation, many Transmission Providers continue to be delayed in completing interconnection studies, which are sometimes months and even years late, including cases when the generator in question would use fossil fuels,<sup>27</sup> and restudies occur quite often. Restudies anywhere in the study process add to these delays and put the development of new generating projects at risk.

These study delays have various consequences, such as costing developers opportunities to enter into PPAs and requiring further studies; as a result, by the time a study is completed, the delays can render the turbine type outdated, for example. Some of these delays have been documented in Commission cases,<sup>28</sup> but most never get that far because, as noted above, a complaint filed under section 206 of the FPA is an inadequate remedy for challenging a Transmission Provider over the processing of a specific interconnection request.

Because GIPs provide that a Transmission Provider is the only entity authorized to provide study results, an Interconnection Customer cannot turn to anyone else for

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<sup>26</sup> See, e.g., *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER12-309-000, Queue Reform Annual Informational Report, Apr. 30, 2014 at 5-7 (stating that Definitive Planning Phase system impact study times had been reduced; however, no facility study completion time data was submitted and System Planning & Analysis study times had increased). AWEA members continue to experience delays in receiving study results in the Midcontinent Independent System Operator, Inc. (“MISO”).

<sup>27</sup> See, e.g., Motion To Intervene, Comments and Request for Technical Conference by American Municipal Power, Inc., Docket No. ER12-1177-000, Mar. 21, 2012 (“AMP Pleading”) (feasibility study results that were successively delayed, with RTO refusing to correct error but instead require Interconnection Customer to pay next successive study deposit). AWEA members continue to experience delays in getting study results in MISO, PJM Interconnection, L.L.C. (“PJM”), and ISO New England, Inc. (“ISO-NE”). AWEA members report that certain Transmission Providers in non-RTO markets are meeting study deadlines, such as Bonneville Power Authority. AWEA members also report that MISO and other RTOs often will complete studies for later-in-time projects while studies for earlier-queued projects continue to languish.

<sup>28</sup> See, e.g., pleadings referenced in notes 26 and 36.

interconnection studies. The Transmission Provider, however, has no obligation under its OATT and GIPs to provide timely study results, because it is only held to a “Reasonable Efforts” standard.<sup>29</sup> The Commission’s *pro forma* GIP requires the Transmission Provider to use Reasonable Efforts to provide: (i) feasibility study results within 45 days after receipt of a signed feasibility study agreement; (ii) system impact study results within 90 days after receipt of a signed system impact study agreement or after the cluster window closes; and (iii) facility study results within 90 days after receipt of a signed facilities study agreement, with a +/- 20% accuracy margin or within 180 days after receipt of a signed facilities study agreement, with a +/- 10% accuracy margin.<sup>30</sup> For restudies, the *pro forma* GIP provides that the Transmission Provider shall take no longer than 45 days (feasibility) and 60 days (system impact and facilities) from the date of notice to perform the restudy.<sup>31</sup> In AWEA members’ experience, studies and restudies are frequently not completed within these timelines.

The Commission has authorized variations for the RTOs, but the “Reasonable Efforts” standard from Order No. 2003 remains the norm in Transmission Providers’ OATTs.<sup>32</sup> The vagueness of the “Reasonable Efforts” standard has previously been brought to the Commission’s attention,<sup>33</sup> and the prevalence of delays in completion of interconnection studies

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<sup>29</sup> Reasonable Efforts is defined in the *pro forma* GIPs as “with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.” Commission *pro forma* GIPs, Definitions.

<sup>30</sup> *See id.* at section 6.3, 7.4 and 8.3.

<sup>31</sup> *Id.* at sections 6.4, 7.6 and 8.5.

<sup>32</sup> *See, e.g.*, ISO New England Open Access Transmission Tariff, Schedule 22, Large Generator Interconnection Procedures; PJM Interconnection Open Access Transmission Tariff, Part VI, section 207, Facilities Study Procedures.

<sup>33</sup> *See, e.g.*, *Southwest Power Pool, Inc.*, 128 FERC ¶ 61,114 at P 21 (2009) (not responding to party’s argument that “[Southwest Power Pool’s (“SPP’s”)] commitment to use Reasonable Efforts to meet the time limitations governing its studies is insufficient, as SPP’s record over the past two years has shown that SPP’s duty to exercise Reasonable Efforts has not been enough for SPP to keep pace with the volume of pending interconnection requests”); *California Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,292 at PP 188, 204 (2008) (rejecting arguments



shows it is a standard with little impact. Petitioner submits that the Reasonable Efforts standard is no longer just and reasonable, as it is vague and imposes no consequences on a Transmission Provider that fails to comply with OATT timelines to complete studies.<sup>34</sup> Just as an Interconnection Customer faces a risk for failing to meet GIP requirements, a Transmission Provider also should be held responsible for failing to meet the direct requirements of the OATT if a study is delayed, rather than being able to defend its delays on the basis that it applied Reasonable Efforts.

There is no legitimate reason why a Transmission Provider cannot be required to deliver study results by the dates listed in a GIP. The entire process is within its control, and more than 10 years after Order No. 2003 was issued, Transmission Providers have developed extensive experience at performing interconnection studies. The lack of consistent, timely study results is costly to generation developers (and to consumers) and is an impediment to developing the next wave of new generation that is needed for the United States.

To remedy this situation, the Reasonable Efforts standard should be removed from the Commission's *pro forma* GIP, and a Transmission Provider should be required to provide study results by the dates listed in its GIP. This change would provide greater certainty for Interconnection Customers and render a Transmission Provider's performance obligation more comparable to what is required by other parts of the OATT.

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of parties requesting elimination of Reasonable Efforts standard on basis that it does not impose any obligations for the CAISO and the PTOs to complete studies or facilities construction on time).

<sup>34</sup> See, e.g., ISO New England Open Access Transmission Tariff, Schedule 22, Large Generator Interconnection Procedures section 6.3: "at any time the System Operator or the Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the System Operator is unable to complete the Interconnection Feasibility Study within that time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required."

Accordingly, AWEA urges the Commission to find that late study and restudy results are not just and reasonable and are not in the best interest of providing efficient means to finance and develop new generation and therefore amend the *pro forma* GIPs to:

- require the Transmission Provider to list standardized dates by when it will provide feasibility study, system impact study, facilities study and restudy results in draft form, and then in final form, to the Interconnection Customer; and
- eliminate the Reasonable Efforts standard in the GIPs.

**ii. The GIPs Should Require the Transmission Provider to Provide Accurate Final Interconnection Study and Restudy Results**

Just as Interconnection Customers are dependent on timely completion of studies, they require that these study results be accurate. This means that the description of facilities and associated cost estimates in the near-final and final study, typically a facilities study, which then are captured in the GIA, are not later revised in a way that causes unexpected cost increases to the Interconnection Customer. The Interconnection Customer is relying on the Transmission Provider's study results at each phase (feasibility, system impact and facilities) to assess the potential cost and timing to interconnect the generation project so it can determine whether to continue with the development of that project. Based on each set of study results, the Interconnection Customer makes an additional commitment of funds to finance the next rounds of Transmission Provider studies, and also decides whether to enter into commercial transactions to support the generation project, such as financing arrangements, land acquisition and generation facility component commitments. These decisions are made in reliance on the study results provided by the Transmission Provider.

The Interconnection Customer is required to provide very large and in some cases non-refundable deposits or the Transmission Provider will not move forward and evaluate the

proposed project.<sup>35</sup> In return, the Interconnection Customer relies on receiving accurate study results. However, in numerous instances, AWEA's members have received study results and draft GIAs that later turn out to have been inaccurate about the required upgrades and their costs. In some cases, Transmission Providers attempt to change the list of network upgrades or the cost of those upgrades after the GIA has been executed. Some of these instances have been documented before the Commission.<sup>36</sup>

Lack of accurate study results harms Interconnection Customers, as network upgrade costs are a significant cost component of building new generation, and accurate information is critical. An unexpected increase in the cost of network upgrades can adversely impact the financial viability of a project. The Interconnection Customer must be able to rely on the network upgrade costs in the Transmission Provider's study results before signing the GIA and proceeding with the project. Instead, the Transmission Provider has been able to revise study results and amend GIAs to impose new and unexpected costs on a project. The possibility of a moving target after study results are provided, and especially once the GIA is effective, can

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<sup>35</sup> See, e.g., *Southwest Power Pool, Inc.*, 147 FERC ¶ 61,201 (2014) (conditionally accepting substantial increased queue study milestone deposits and conditions when the amount may be non-refundable); *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,253 (2012) (accepting rules that require Interconnection Customer to forfeit new and increased M2 milestone deposit if it withdraws its project).

<sup>36</sup> See, e.g., *Midcontinent Indep. Sys. Operator, Inc.*, Motion to Intervene and Protest of South Fork Wind, LLC, Docket No. ER15-954-000, Feb. 20, 2015, at 3 (“[l]ate in the restudy process . . . MISO . . . determined that the study had failed to include certain generators interconnecting on the same line as South Fork,” and “[a]fter correcting this error,” MISO reduced South Fork’s injection capacity); *Midwest Indep. Transmission Sys. Operator, Inc.*, 135 FERC ¶ 61,222 (2011), *reh’g denied*, 143 FERC ¶ 61,050 (2013) (MISO and contracting interconnecting transmission owner failed to follow a specified requirement in the Business Practice Manual for performing interconnection studies, causing MISO to run additional studies months *after* the GIA was executed and resulted in more than \$10 million in additional network upgrade costs for the Interconnection Customer and years of delay); see also AMP Pleading, *supra* (feasibility study contained errors identifying network upgrades costing between \$52-104 million; *PJM Interconnection L.L.C.*, Motion to Intervene and Comments of Acciona Wind Energy USA LLC, Docket No. ER12-1177-000, at 10, Mar. 21, 2012 (Interconnection Customer was provided study results identifying the need for \$250 million in network upgrades that was later corrected to \$1.5 million). In various other instances that have not led to filings with the Commission, Interconnection Customers have been presented with much higher upgrade costs than expected, but following greater scrutiny by the Interconnection Customer, the interconnecting transmission owner has revisited its proposed upgrades and presented different upgrades with lower costs.

materially harm the economic bargain that the Interconnection Customer expected and adversely impact the continued viability of a generation project.

However, the GIPs contain no provision that requires the Transmission Provider to provide accurate study results. In fact, some Transmission Providers have added measures to the GIA to specifically provide that the Interconnection Customer has no right to rely on the study results that are provided because the Transmission Provider had to rely on information provided by others, including the Interconnection Customer, over which it may not have had control.<sup>37</sup> Such provisions ignore that the scope of information that the Interconnection Customer provides is minimal and, in any event, the Interconnection Customer has every incentive to provide accurate information to the Transmission Provider to help produce accurate studies.

Transmission Providers have been performing interconnection studies for decades and under the GIPs since 2003, and should have ample experience and expertise at performing studies. In fact, in light of this standardized process and an understanding of what it entails, the North American Electric Reliability Corporation (“NERC”) proposed, and the Commission ratified, Reliability Standards specifying what the Transmission Provider must do when performing interconnection studies. FAC-002-2, R1 provides:

Each Transmission Planner and each Planning Coordinator *shall study* the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing

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<sup>37</sup> See, e.g., PJM *pro forma* Interconnection Service Agreement, section 9.0 (“In analyzing and preparing the System Impact Study, and in designing and constructing the . . . Network Upgrades . . . , Transmission Provider, the Interconnected Transmission Owner(s), and any other subcontractors employed by Transmission Provider have had to, and shall have to, rely on information provided by Interconnection Customer and possibly by third parties and may not have control over the accuracy of such information. Accordingly, NEITHER TRANSMISSION PROVIDER, THE INTERCONNECTED TRANSMISSION OWNER(s), NOR ANY OTHER SUBCONTRACTORS EMPLOYED BY TRANSMISSION PROVIDER OR INTERCONNECTED TRANSMISSION OWNER MAKES ANY WARRANTIES . . . WITH REGARD TO THE ACCURACY, CONTENT, OR CONCLUSIONS OF THE FACILITIES STUDY OR THE SYSTEM IMPACT STUDY IF A FACILITIES STUDY WAS NOT REQUIRED . . .”). Similar disclaimers are in PJM’s system impact study agreement and facilities study agreement.

interconnections of generation, transmission, or electricity end-user Facilities. The following *shall be studied*:

- 1.1. The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s);
- 1.2. Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements;
- 1.3. Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and
- 1.4. Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, *the results shall be evaluated and coordinated* by the entities involved. (Emphasis added.)

Further, “Each Transmission Planner or each Planning Coordinator *shall have evidence* (such as study reports, including documentation of reliability issues) *that it met all requirements in Requirement R1.*”<sup>38</sup> And FAC-001-1, R1 provides a litany of items that must be addressed in evaluating a proposed interconnection. Transmission Providers cannot claim they are incapable of meeting these standards or translating the results into the necessary upgrade requirements. An interconnection Customer should be able to rely on a requirement that the Transmission Provider provide accurate and reliable study results such as these NERC standards mandate.

AWEA urges the Commission to find that the just and reasonable cost-effective development of new generation requires the provision of accurate study results. To effectuate these findings, AWEA urges the Commission to amend the *pro forma* GIPs to:

- require the Transmission Provider to provide accurate final interconnection feasibility, system impact, facilities study and restudy results to the Interconnection Customer;
- require the Transmission Provider to affirmatively communicate to the Interconnection Customer that such study results are final; and

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<sup>38</sup> FAC-002-2, M1 (emphasis added); *see also* FAC-001-1, R3, R4; FAC-001-2, R3.

- require the Transmission Provider to remove any OATT, GIPs and GIA provisions which provide that the Interconnection Customer may not rely on the Transmission Provider's study results.

**iii. The GIPs Should Provide For a Single, Annual Restudy to be Completed Each Year, or Otherwise Provide Network Upgrade Cost Certainty**

In some instances, certainty for Interconnection Customers has been delayed by repeated restudies. In MISO, for example, this has caused considerable delays in getting interconnection study results and finalized GIAs. Many conditions listed in an OATT and GIA can trigger a restudy, including when a higher-queued project drops out of the queue. This prompts a restudy, delaying the completion of the study results, and, in effect, restarting the process. Other events, such as the cancellation or reconfiguration of a transmission project, may trigger yet another restudy, which again restarts the process. This can leave the Interconnection Customer without a GIA or any indication of the cost of network upgrades for which it might be responsible. Even if the Interconnection Customer has a GIA and begins to construct its project, the Transmission Provider might call for a restudy once or several times a year because higher queued-projects dropped out of the queue at different times. This is extremely disruptive to the development process.<sup>39</sup>

AWEA members recognize that restudies are often needed, hence their inclusion in the *pro forma* GIPs. But restudies can drag on for too long due to continual changes that cause the Transmission Provider to have to reconfigure the study and recommence it.

A potential solution is to move to an annual restudy process where the Transmission Provider considers all relevant system condition changes and all higher-queued projects that

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<sup>39</sup> In the *Neptune* case, the Commission recognized that repeated restudies due to unanticipated events can cause an interconnection customer to “be unable to make reasoned business decisions,” as “a never-ending series of changes” has the effect of “creating havoc for interconnection providers and customers alike.” *Neptune Regional Transmission System LLC v. PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,098 at P 23, *order on reh'g*, 111 FERC ¶ 61,455 (2005) (“*Neptune*”).

dropped out of the queue in one restudy for the applicable projects in a cluster or sub-region. Thus, for example, assume the Transmission Provider will perform its annual restudy on January 1, 2017. Assume further that higher-queued projects drop out of the queue in June 2016 and October 2016. Interconnection studies being performed during 2016 would not be disrupted to account for the higher-queued drop outs. Rather, the Transmission Provider would complete those studies according to the time listed in its GIPs, provide the results to the Interconnection Customer and tender a GIA, as applicable. Then, on January 1, 2017, the Transmission Provider would start a restudy for each applicable cluster of Interconnection Customers that takes into account the higher-queued drop outs and any other relevant system change. The restudy would model system impacts and identify any changes in network upgrades to accommodate all applicable Interconnection Customer projects. The Interconnection Customer with a GIA would be provided with new information about its project. The Interconnection Customer that is due to get study results in July or November 2016, for example, will get those results on time and proceed to a GIA if desired, but then get any new information regarding network upgrades when the January 1, 2017 restudy is completed. The Transmission Provider would not start another restudy until January 1, 2018, at which time it would again model system impacts and identify any change in network upgrades to accommodate all applicable Interconnection Customers.

Thus, each restudy would be completed, rather than re-started due to intervening events, and thereby provide the Interconnection Customer with some information on likely network upgrades. In some cases, an annual restudy may potentially prolong the time until an Interconnection Customer receives updated study results, but the trade-off in getting a GIA, which is needed to support financing and a PPA – is worth it for many Interconnection

Customers. Further, the Transmission Provider will benefit from fewer restudies. Overall, such an approach can provide more predictability and provide for a better use of resources.

Alternatively, the Commission could consider how restudies are handled in the CAISO's study process. In response to the Commission's directive to address means to clear out the queue backlog, CAISO adopted its Phase I and Phase II interconnection study processes. CAISO collapsed certain of the studies and provided network upgrade cost information earlier in the process.<sup>40</sup> Under Phase I, CAISO evaluates the impact of all interconnection requests in a cluster, preliminarily identifies all network upgrades and interconnection facilities for each interconnection request, establishes a maximum cost responsibility for network upgrades assigned to each interconnection request and provides a good faith estimate of the cost of interconnection facilities.<sup>41</sup> Prior to running its Phase II study, CAISO performs a reassessment of its base case that takes into account system changes and projects that dropped from the queue. CAISO then uses its updated base case to run its Phase II study which sets the Interconnection Customer's cost obligation for network upgrades. The reassessment does not affect the Interconnection Customer's maximum cost obligation determined in Phase I, which serves as a cost cap for network upgrades. In addition, CAISO does not continually restart the study process to account for generators that drop out the queue, and instead does this once during its reassessment. Indeed, when CAISO proposed its two-phased study process, it explained to the Commission that restudies were no longer necessary and noted that restudies "pose the potential to divert Interconnection Study resources and perpetuate the types of delays in the

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<sup>40</sup> ERCOT has similarly collapsed the system impact and facilities study and moved to a Full Interconnection Study. *See*, ERCOT Planning Guide, January 1, 2015, section 5.

<sup>41</sup> *See* CAISO Tariff, Appendix DD, section 6.2; *see also id.*, sections 6.3.2.1.1 and 6.3.2.2.



interconnection process that have led to the current [queue backlog and delay] situation.”<sup>42</sup> The CAISO does, however, allow limited scope amended studies to address Interconnection Customers’ allowed change requests provided that the change does not have material impact on other queued projects.

Accordingly, the Commission should find that delays resulting from restart of studies and frequent restudies are not just and reasonable and are not in the best interest of providing efficient means to finance and develop new generation and amend its *pro forma* GIPs to:

- allow a Transmission Provider to perform restudies no more than on an annual basis unless the Interconnection Customer’s costs are capped on the basis of the initial study;
- prohibit the Transmission Provider from restarting a study during the initial study phase to accommodate restudy conditions unless the Interconnection Customer agrees to do so or cost certainty has been provided; and
- allow the Interconnection Customer to request limited scope restudies at times other than annually provided that such restudies do not impact other queued projects.

**iv. The GIPs Should Require Contingent Facilities to Be Electrically-Relevant to the Project Being Studied, and Be Listed In All Studies and the GIA**

In Order Nos. 2003 *et al.*, the Commission noted that, in some cases, interconnection service for a lower-queued customer could be contingent on a higher-queued Interconnection Customer completing certain network upgrades. The Commission required the Transmission Provider to identify such contingent facilities in its interconnection studies and in the GIA.<sup>43</sup>

The list of contingent facilities provides the Interconnection Customer with information about potential additional costs that may be assessed to obtain the level of interconnection service in its interconnection request. An Interconnection Customer needs to be able to rely on

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<sup>42</sup> See *California Indep. Sys. Operator Corp.*, Docket No. ER08-1317-000, Transmittal Letter, Jul. 28, 2008, at 30.

<sup>43</sup> Order No. 2003 at P 409; Order No. 2003-A at P 558.

the detailed contingent facilities listed in its interconnection studies and GIA in order to assess the risk of any increased cost of network upgrades. Transmission Providers, though, are not consistently providing full and accurate lists of electrically-relevant contingent facilities within interconnection studies and the GIA. There is no reason why a complete list of relevant contingent facilities that might impact the requested level of interconnection service, with estimated cost, cannot be known before a GIA is finalized and before the generation developer makes large financial commitments to the Transmission Provider and third parties.

Further, so far as AWEA is aware, GIPs do not provide a clear methodology for how a Transmission Provider determines what is a contingent facility for a proposed generator. AWEA understands that some, but not all, Transmission Provider GIPs or related Business Practice Manuals (“BPM”) acknowledge the need to study contingent facilities.<sup>44</sup> Yet often there is no clear definition of relevant contingent facilities in the GIPs or BPMs, nor is there an affirmative obligation in the GIPs to apprise the Interconnection Customer of such contingent facilities in the facilities study and GIA.

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<sup>44</sup> See, e.g., NYISO Attachment X, sec. 30.6.2, Scope of Interconnection Feasibility Study (the Interconnection Feasibility Study generally will consider all generating and merchant transmission facilities, System Upgrade Facilities and System Deliverability Upgrades that “(i) are directly interconnected to the New York State Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have accepted their cost allocation for System Upgrade Facilities and posted security for such System Upgrade Facilities in accordance with Attachment S; and (iv) have no Queue Position but have executed a Standard Large Generator Interconnection Agreement or requested that an unexecuted Standard Large Generator Interconnection Agreement be filed with FERC.”); CAISO Appendix U (LGIP), section 2.3 Base Case Data (“The CAISO . . . shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request . . . . Such Base Cases shall include (i) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the transmission system for which a transmission expansion plan has been submitted and approved by the applicable authority.”); CAISO BPM, sec. 3.3 - Generator Interconnection and Deliverability Allocation Procedures, at 18 (The base case data posted shall include the power flow base cases for Deliverability Assessment and reliability assessment, short circuit duty base cases, and contingency lists); PJM, BPM, sec. 2.2.2 System Impact Study Analysis and Schedule, at 20 (Relationships are studied between the new generator or the new transmission facility, other planned new generators in the queue, and the existing system as a whole); MISO BPM at 21 (During the system impact study, “The ad hoc group will provide any additions or changes to the MTEP contingency file during the Model Review period. This file will also include contingencies in Affected Systems and the lower voltage contingencies as appropriate for the study).

In some cases the appendices to a GIA have a long list of contingencies including higher-queued generators throughout the RTO and numerous transmission upgrades. However, no showing has been made whether these potential projects and facilities will in fact have an impact on a particular project under the GIA, or what such impact might be in terms of financial costs or timing. Yet because they are listed, these contingencies create uncertainty as to potential upgrade costs for, and curtailment of, the proposed generating project.

The GIPs should be amended to provide a clear definition of contingent facilities based on their relationship to the project under a GIA, how contingent facilities will be treated in the studies, and the requirement to identify contingent facilities in the facilities study and GIA. Without clarity on this issue, there is far too much uncertainty on what is a legitimate contingency and what costs might potentially be imposed on the Interconnection Customer in the future.

MISO has grappled with how to define the list of contingencies and has at times included a long list of contingent facilities in the appendices to GIAs, but has been adjusting its methodology for determining which facilities are significantly related to an interconnection request.<sup>45</sup> MISO's revised methodology studies an Interconnection Customer's project's impact on MISO Transmission Expansion Plan ("MTEP") Appendix A projects and higher-queued generators and their required network upgrades under base case and N-1 conditions. Those facilities that have a 5% or greater distribution factor impact from the Interconnection Customer are listed as contingent facilities in the GIA. This has resulted in a reduction of contingencies listed on the order of 85% by focusing on those contingent facilities that are electrically impacted by the Interconnection Customer's proposed generating project. All Transmission Providers

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<sup>45</sup> See discussion in MISO's 2014 Queue Reform Annual Informational Report, Apr. 30, 2014 at 4.

should be required to publish a similar methodology in their GIP so as to limit unnecessary and incorrect listings of contingencies in GIAs.

The Transmission Provider also should not be allowed to list as contingent facilities network upgrades that are or may be required for reliability planning, as the costs of these cannot be imposed on the Interconnection Customer. The Commission has limited the discretion of the Transmission Provider to transform network upgrades that were planned for multiple purposes into network upgrades that are unnecessary but for the Interconnection Customer's project.<sup>46</sup> That policy should be universally applied to all Transmission Providers.

Accordingly, AWEA urges the Commission to find that it is just and reasonable and in the best interest of providing efficient means to finance and develop new generation for the Interconnection Customer to have contingent facility information and therefore to amend the *pro forma* GIPs to:

- require the Transmission Provider to include in GIPs a methodology for identifying electrically-relevant contingent facilities;
- require the Transmission Provider to consider all electrically-relevant contingent facilities in its interconnection studies and to list all such facilities in the study results;
- require the Transmission Provider to provide information in studies about the financial implications and currently known estimated cost impact of contingent facilities;
- require the Transmission Provider to list in GIAs all the contingent facilities that are electrically relevant to provide the requested level of interconnection service; and
- prohibit the Transmission Provider from including as contingent facilities for which the Interconnection Customer may have cost responsibility any transmission lines that have been required by the local or regional transmission plan.

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<sup>46</sup> See *Jeffers South, LLC v. Midwest Indep. Transmission Syst. Operator, Inc.* 144 FERC ¶ 61,033 at P 64 (2013).

**v. The GIPs Should Require Transmission Providers and Owners To Provide Cost Estimates Earlier In The Process**

Receiving good faith cost information at the earliest possible stage is important to Interconnection Customers, who can then make decisions about whether to proceed with a project. Under the model set up in the *pro forma* GIPs, the Transmission Provider produces a system impact study that provides information about interconnection facilities and network upgrades that will be needed to address the proposed interconnection of the generating project. The *pro forma* GIPs provide that, for the system impact study, the Transmission Provider “will provide a list of facilities that are required as a result of the [i]nterconnection [r]equest and a non-binding good faith estimate of cost responsibility.”<sup>47</sup> In an RTO context, the RTO’s primary focus is the identification of facilities needed to address system impact and reliability. Thus, for example, it may identify the need to reductor a line. In some cases, the RTO’s cost estimate is a rough figure that is not based on specific and current information from the interconnecting transmission owner pertaining to the project being studied.<sup>48</sup> This is because the transmission owner may not become more involved until the facility study phase. Once the transmission owner becomes more involved, it may reach further conclusions about needed upgrades, *e.g.*, in addition to reductoring a line, it may determine that the towers need to be replaced as well – which AWEA members have experienced. Cost estimates in the facilities study, thus, can vary significantly from, and have been much higher than, the estimate in the system impact study, disrupting the Interconnection Customer’s commercial expectations. It is reasonable and necessary to provide this more accurate cost information to the Interconnection Customer before the late-stage facilities study.

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<sup>47</sup> Order No. 2003, GIPs, section 7.3.

<sup>48</sup> AWEA members have experienced this in, for example, PJM and MISO.

CAISO has a practice that provides cost information at an earlier stage. As noted above, in response to the Commission's directive to find means to clear out the queue backlog, CAISO collapsed certain of the studies into a Phase I and Phase II process. Under Phase I, CAISO evaluates the impact of all interconnection requests in a cluster, preliminarily identifies all network upgrades and interconnection facilities and assigns to each interconnection request a maximum cost responsibility for network upgrades.<sup>49</sup> CAISO is able to assign maximum network upgrade cost information in Phase I because each Participating Transmission Owner ("PTO") is required annually to publish its per unit cost for facilities generally required for interconnection.<sup>50</sup> CAISO uses these annual per unit costs to develop the network upgrade costs assigned to each Interconnection Customer. CAISO later performs a reassessment that takes into account projects that have withdrawn from the queue, downsized projects and changes from its current regional transmission plan.<sup>51</sup> After that, CAISO undertakes its Phase II study which, among other things, refines the network upgrade cost responsibility amounts assigned to each Interconnection Customer.<sup>52</sup> However, the network upgrade cost amount charged to an Interconnection Customer will not exceed the value provided with the earlier Phase I study results.<sup>53</sup> This process has been in place for years and has worked well to support the development of new generation.<sup>54</sup>

There is merit to incorporating the CAISO approach in all GIPs as a best practice. The practice will have many benefits, including (1) allowing the Interconnection Customer to make

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<sup>49</sup> See CAISO Tariff, Appendix DD, section 6.2; see also *id.*, sections 6.3.2.1.1 and 6.3.2.2.

<sup>50</sup> See *id.*, section 6.4.

<sup>51</sup> See *id.*, section 7.4.

<sup>52</sup> See *id.*, sections 8.1-8.4.1.

<sup>53</sup> See *id.*, section 10.1(a).

<sup>54</sup> See *California Indep. Sys. Operator Corp.*, 124 FERC ¶ 61,292 (2008).

informed decisions earlier in the process and thus preserving resources or enabling it to secure a PPA and other commitments earlier, (2) moving projects out of the queue earlier because they receive better cost estimates for network upgrades earlier, which, in turn, will support a more manageable queue for the Transmission Provider and (3) contributing to reducing the occurrence of late studies because one less study needs to be provided.

Although the CAISO phased process may not be the sole means of providing facility study-type cost information earlier in the process, it could be adopted if no other method is shown to be superior. Accordingly, the Commission should find that the current practice of providing network upgrade cost estimates during the facilities study stage is unjust and unreasonable and not in the best interest of developing new generation and amend its *pro forma* GIPs to:

- require the interconnecting transmission owner and other affected system owners to provide facility cost information at the system impact study phase; or
- require the Transmission Provider to adopt the CAISO two-phased approach.

**vi. A Transmission Provider's GIPs Should List Standardized Study Costs**

An Interconnection Customer has no way to ensure that a Transmission Provider charges study costs that are reasonable and reflect only those needed to evaluate the interconnection request. Although Transmission Provider GIPs typically state the deposits required for the various studies, they do not provide information on the costs of the studies, nor do they cap those costs.

Not surprisingly, AWEA's members have encountered a wide disparity in the costs assessed by Transmission Providers to perform the same basic studies. For example, some Transmission Providers have charged \$28,000 for a facilities study for a 115 kV 3-breaker ring bus and \$95,000 for a full interconnection study that includes steady state, short circuit, stability,

and a facilities study for a 345 kV breaker position in an existing substation. By comparison, another Transmission Provider charged \$320,000 to perform a facility study for relaying work at two existing substations. Another Transmission Provider charged \$250,000 to perform a facility study for a single breaker addition in an existing substation. There should not be such disparity in study costs. The disparity suggests that some Transmission Providers are efficient, while others do not perform the service as cost effectively or efficiently as possible.

The current GIPs have no mechanism to ensure that the Interconnection Customer is charged a just and reasonable cost for interconnection studies and that the Transmission Provider does not charge for interconnection studies on a discriminatory or preferential basis among Interconnection Customers, including an affiliate. This lack of transparency should be remedied. If the Interconnection Customer disagrees with or questions the study cost amount, the options to resolve the issue, at that point, are either dispute resolution (such as in an RTO) or a FPA section 206 complaint at the Commission, both of which are time consuming and have the potential to derail a proposed generation project. To rectify this, the GIPs should require that there be basic study fees, which could then be increased only when the Transmission Provider includes an itemization of extraordinary expenses beyond its control that warrant the higher study costs. This would also require more transparency by Transmission Providers in the use of outside consultants to perform studies, including the specific tasks, timelines, and rates involved. When the Transmission Provider intends to charge the Interconnection Customer for such expenses, it would have to justify the particular costs in light of the complexity of the studies in question. This would ultimately lead to greater transparency and consideration of whether the interconnection process would be better served by the Transmission Provider acquiring resources to perform studies directly or use outside consultants.



Transmission Providers have been preparing these studies for years and have the ability to list the cost. AWEA is mindful that costs can change from year to year, and one means to address this would be for the Transmission Provider or transmission owners within an RTO to annually post study cost amounts.

To fix this issue, AWEA urges the Commission to find that the current process of not publishing and standardizing study costs is unjust and unreasonable and can be unduly discriminatory and thus to amend the *pro forma* GIPs to:

- require the Transmission Provider to list in its GIPs or post on its website standard study costs, and an appropriate accuracy margin that will act as a cap;
- provide that the Transmission Provider shall have no right to collect from the Interconnection Customer true-up amounts for the actual cost of studies beyond the posted costs plus the accuracy margins; and
- allow the Transmission Provider to collect study costs above the accuracy margin only to the extent such costs are demonstrated as extraordinary and beyond the control of the Transmission Provider.

**B. Reforms to Improve Transparency in the Interconnection Process**

**i. Transmission Providers Should Provide More Information on the Assumptions Used in the Studies, and When Possible, Give Interconnection Customers Options Related to Upgrades and Curtailment**

To increase transparency and consistency in interconnection studies, the GIPs should require Transmission Providers to better justify the assumptions they use in interconnection studies and when possible, give the Interconnection Customer options related to upgrade costs and the tradeoff of potential curtailments. Following are various examples of how Transmission Provider assumptions and modeling can lead to inaccuracies and uncertainty.

An example of the type of assumptions that are relevant to interconnection studies is the use of light-load scenarios. PJM is currently considering how to address the impact of wind

energy production (as well as nuclear energy production) during times of low demand, such as during the middle of the night. If interconnection studies are modeled in such a way as to assume high output of these generators during times of low demand, the results can lead to construction of more costly network upgrades to increase flow of energy. Also, several MISO “Ad Hoc” groups recently have included “light-load” scenarios in the interconnection studies by studying system impacts at low load periods. This too may result in more network upgrades being required for Interconnection Customers studied under light-load scenarios. These RTOs implement these study revisions *outside* of the OATT, through their BPMs. This practice raises two questions – whether the Transmission Provider should use these light-load assumptions, and if it does, whether the Interconnection Customer should have the option of being curtailed during light-load periods rather than being forced to sponsor costly upgrades. The GIPs should be revised to compel resolution of these questions, rather than leaving them to individual Transmission Providers to resolve unilaterally through BPMs or other means. The issue bears directly on rates for interconnection service.

A related problem is the modeling of generating resources that are contributing to the levels of congestion and curtailment. RTOs consider the system shift factor impact of adding a new generating project to determine whether network upgrades are needed. CAISO uses a 5% flow impact threshold to determine whether an interconnection request contributes to a network upgrade.<sup>55</sup> Others, however, use a very high shift factor. MISO, for example, refers to a 5% shift factor in its BPMs to determine if network upgrades are needed. However, AWEA members understand that MISO actually uses the shift factor incorporated in a member transmission owner’s planning criteria, which can be 3%, 5% or as high as 20%. Use of different

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<sup>55</sup> See, e.g., CAISO Generator Interconnection and Deliverability Study Methodology Technical Paper, July 2, 2013, at 19.

shift factors can lead to unjust, unreasonable and unduly discriminatory results, as network upgrade costs will vary greatly between generators that compete in the same and neighboring markets and lead to certain generators subsidizing other generators' use of the grid. An RTO should use the same standard in all sub-regions and zones, *e.g.*, 5%. Use of a very low shift factor such as 3% may trigger too many network upgrades. On the other hand, if the shift factor is too high, no network upgrades may be required, *e.g.*, with a 15% shift factor, the need for upgrades is triggered only if a new generator has a 15% impact on relevant facilities.

A problem arises, however, when several generation projects are added over time, and each does not reach the shift factor threshold. Each project then connects without network upgrades, but the cumulative impact of these below-threshold generation projects causes a significant cumulative impact on a localized system. Too high shift factors thus exacerbate congestion and potential curtailment, which can be avoided through use of lower shift factors. MISO has been considering an additional solution where it will look at the cumulative effect of the generators in a cluster or group and if it reaches a 20% or greater impact on the rating of a facility, then generators will be responsible for network upgrades. This is the type of modeling idea that attempts to ensure that cumulative impacts are addressed.

Another problem is the lack of accuracy in how injection levels are modeled by generators. From AWEA members' experience, in SPP, for example, a new wind generator within one balancing area is modeled at a certain level of injection, *e.g.*, 100% of nameplate MW output, while existing wind generators within the same balancing area are modeled in the study at a different level, *e.g.*, 80%, and wind generators in a neighboring balancing area modeled at 20%.<sup>56</sup> The model may not create a realistic set of assumptions about the actual level of

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<sup>56</sup> See Guidelines for Generation Interconnection Requests to SPP's Transmission System (Revised 1-16-2015), at 9. The 80% figure is obtained from discussions with SPP.

injections by the generators, and can lead to unforeseen outcomes when the new generator starts injecting and experiences unexpected curtailments. A better practice would be to model the output of existing generators based on persistence or operational data.

MISO and PJM also have guidelines that describe assumed dispatch levels by generation type. However, the dispatch assumptions often differ from historical patterns. For example, PJM is proposing to study wind plants at 100% of output during light load conditions, even though the highest fleet-wide capacity factor seen in 2014 was 86%, and the highest wind fleet capacity factor during extremely low demand hours was 70%. PJM has also proposed to assume that electricity demand is 35% of peak demand during light load hours, even though the lowest demand level in 2014 was 41% of peak demand. The energy dispatch and load profile assumptions used in study models translate to network upgrades that generators are being required to fund.<sup>57</sup>

CAISO, likewise, does not apply accurate assumptions. In its interconnection reliability studies, CAISO assumes 100% generation from wind resources which does not correspond to historical or expected wind generation for such load condition. For deliverability studies, CAISO uses generation dispatch scenarios, both for existing resources (conventional and renewable) or queued resources, that are totally unrelated to the way generators are expected to operate or have historically operated but are created to simulate unrealistic stress in parts of the transmission system.

ISO-NE also has been developing a technical guide for how all types of studies should be performed. The guide was recently presented to the Planning Advisory Committee.<sup>58</sup> Section

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<sup>57</sup> See <http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx> and <ftp://ftp.pjm.com/operations/wind-web-posting/2014-hourly-wind.xls>

<sup>58</sup> The latest version is available at [http://iso-ne.com/static-assets/documents/2014/12/planning\\_technical\\_guide\\_2014-12-2\\_clean.pdf](http://iso-ne.com/static-assets/documents/2014/12/planning_technical_guide_2014-12-2_clean.pdf).

11.2 shows the output levels from each type of generator in each type of study. Although this document is still being finalized, and more transparency is needed on how generator output is modeled, such guides can be highly valuable by providing a transparent, centralized repository of the standard assumptions to be used.

Instead of using standard assumptions, Transmission Providers should be required to model their system based on reasonable expected output of all generators including the one(s) being studied and expected load profiles for applicable zones. The Transmission Provider has economic models that identify the security constrained economic dispatch, by generation type, during times of the day. This will ensure that required network upgrades are commensurate with the generator's actual impact and actual load profiles.

Once study assumptions are substantiated, the Transmission Provider should then make this information transparent to the marketplace. Further, there should be a requirement to update the modeling assumptions every two years to ensure they reflect actual system conditions. This is especially needed as the generation mix changes.

Accordingly, AWEA urges the Commission to find that the lack of transparency and substantiation of assumptions used to develop interconnection studies is unjust and unreasonable and thus to modify the GIPs to:

- require the Transmission Provider to list the specific study processes and assumptions for forming network models used for interconnection studies, including shift factors and dispatch assumptions, in its GIP;
- require the Transmission Provider to perform its studies consistent with the study processes and assumptions listed in its GIP;
- require the Transmission Provider to update its study process, inputs and assumptions every two years and then post the new results; and
- allow an Interconnection Customer to elect to not be studied as being dispatched simultaneously to certain local generation in its interconnection studies, particularly

for off-peak operating scenarios, in order to identify the upgrades that would be required to allow the proposed generator to operate concurrently with existing local generation.

**ii. Curtailment Risk Information Should be Provided on a Transmission Provider's Website and in its Interconnection Studies.**

In certain regions, Interconnection Customers can choose between obtaining Network Resource Interconnection Service ("NRIS") and Energy Resource Interconnection Service ("ERIS"). For NRIS, the Transmission Provider studies the impact of interconnecting 100% of the nameplate MW capacity of a proposed project. The Interconnection Customer pays for the network upgrades identified and in return is provided the right to inject up to 100% of its MW capacity. For ERIS, the Transmission Provider studies the interconnection of a MW capacity amount that is less than the project's nameplate capacity (although, as noted above, some RTOs assume as much as 100% dispatch during "light-load" or "shoulder" periods). The Interconnection Customer pays for network upgrades to accommodate this lower amount of capacity, but is allowed to inject up to as much as 100% of the project's MW capacity on an as-available basis. An Interconnection Customer that chooses ERIS develops business plans based on the availability to use as-available transmission capacity.

In other regions, such as ISO-NE, all interconnection studies are performed using the Network Capability Interconnection Standard, previously known as the Minimum Interconnection Standard, in which the proposed generator is dispatched simultaneous to existing local generation to identify the least-cost upgrades required for the proposed generator to reliably interconnect and begin competing with the existing generation. The proposed generator is given no information about its ability to operate at the same time as existing area generation nor is it allowed to choose to have its interconnection study identify the upgrades required for it to operate at the same time as the existing local generation. Both the existing and proposed

generation will compete for the as-available transmission capacity without knowing ahead of time what the extent of competition is likely to be for use of the limited capacity. This is not a model on which new generation can be financed and built.

As another example, when previously uncongested transmission lines attract generation development and become congested, the as-available capacity is reduced or eliminated. As a result, a project may operate for several years, injecting up to 100% of its energy, but is not aware of other generating projects being planned for the area that will eat into the as-available capacity. Similarly, the new generating projects coming on line have no or little idea that the as-available capacity is going to be very low. To help provide more transparency and promote efficient investment decisions, Interconnection Customers should be provided with system information in interconnection studies showing the extent of potential congestion on relevant transmission lines or interfaces and have access to such information thereafter.

This problem has been presented to the Commission. Many unaffiliated wind generators in MISO and neighboring PJM sited new projects in the same geographic wind corridors. Each project had no idea of the effect that other subsequent projects would impose on use of the as-available ERIS capacity. As a result, projects installed in 2008 and 2009 initially used significant as-available capacity. But projects added each year in the same vicinity consumed the as-available capacity expected by earlier-in-time generators. Subsequent projects were studied and allowed to interconnect for ERIS but were not told about the potential for significant congestion in the area. This resulted in all existing generators in this area being curtailed at extraordinary levels and experiencing significant losses in expected revenue.<sup>59</sup>

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<sup>59</sup> See *Northern Indiana Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc. and PJM Interconnection, L.L.C.*, Complaint of Northern Indiana Public Service Company, Docket No. EL13-88-000, filed Sept. 11, 2013; Comments In Support Of Complaint Of E.ON Climate & Renewables North America LLC, Docket No. EL13-88-000, filed Oct. 31, 2013.

For a short time, MISO provided summary curtailment information that allowed an Interconnection Customer to see a monthly list of congested facilities.<sup>60</sup> MISO no longer provides such information to the marketplace. Presumably this is because MISO switched to a dispatchable resource model for wind generation, where curtailment is based on economics. Yet, constraints on capacity are what drive locational marginal prices (“LMP”); thus, the move to a dispatchable model does not obviate the need for congestion information. MISO and other Transmission Providers should be required to post information similar to what MISO used to post.

In January of each year, ISO-NE provides an annual report on flows across the major New England transmission interfaces broken down by month of the prior year.<sup>61</sup> This type of information can be extremely valuable for Interconnection Customers and existing generators trying to understand their curtailment risks. However, this data is not made available for local interfaces in New England that are the primary cause of curtailment. Such information should be made available by ISO-NE and other Transmission Providers for all interfaces, regardless of voltage level, that could impact the delivery of energy from new generation. This information would help developers intelligently site their projects and is the type of information that should be made available on all Transmission Provider systems in the United States.

Accurate reporting of existing congestion – and forecasts of congestion as planned generation projects come on line – would also help maximize efficient use of the existing grid. With accurate information on future congestion, developers would be less likely to oversaturate a transmission corridor and more likely to develop projects in other areas. Accurate information of

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<sup>60</sup> The past MISO curtailment information is available at:  
[http://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Wind\\_Curtailment\\_Constraints.html](http://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Wind_Curtailment_Constraints.html).

<sup>61</sup> The 2014 report is available at: [http://iso-ne.com/static-assets/documents/2015/01/a5\\_2014\\_lmpps\\_interface\\_mw\\_flows.pdf](http://iso-ne.com/static-assets/documents/2015/01/a5_2014_lmpps_interface_mw_flows.pdf)



existing and future congestion would also likely reduce the demand for interconnection studies on oversaturated transmission corridors and the pressure on Transmission Providers to complete those studies.

Current study processes also need to be updated to provide a more accurate picture of the available capacity landscape that will occur upon interconnection. By way of example, if there are five generation projects in a sub-region of an RTO that propose to interconnect during 2017-2020, the RTO will likely perform cluster studies looking at system conditions in 2020 and require all five projects to adopt a commercial operation date of 2020. RTO OATT rules may allow interconnection before 2020, however, on a conditional, temporary or provisional basis if system conditions allow until required network upgrades are installed in 2020. Thus, for example, one of the five projects might be allowed to provisionally interconnect in 2017. That project will accelerate capital investment on the assumption that it will have means to inject and sell energy at that earlier date. Projects have done this only to experience significant levels of congestion and curtailment and thus an inability to utilize even the lower, provisional expected level of interconnection service. This has occurred because of a lack of information about system conditions in interconnection studies. Although the cluster studies address system conditions in 2020 (and even those need to provide information on curtailment risk as of 2020), they provide no information about congestion and curtailment risk in 2017, 2018 or 2019. This gap needs to be closed.

The GIPs should provide a mechanism for an Interconnection Customer that is part of a cluster to obtain information about connecting its individual project provisionally in 2017, for example. That mechanism is not available under the current GIPs study processes. The Optional Study route under the GIPs is not an effective mechanism because, in practice, the Transmission

Provider continues to tie its operational assessment to system conditions after the GIA is executed, or after commercial operation has been achieved, based on the required network upgrades being installed in 2020, for example. The Interconnection Customer needs an operational assessment of modeled system conditions before the later network upgrade-based commercial operation date of 2020. There is no reason why such information cannot be provided to the Interconnection Customer as part of the interconnection study process. MISO already does this, in part, with its Quarterly Operating Limit study that it runs before a GIA is executed.<sup>62</sup>

Consumers benefit from early availability of new generation, even on a provisional basis. Yet, the Interconnection Customer cannot wisely commit to sell power under a PPA, with provisional interconnection service in 2017, for example, without information on full and complete expected system conditions in 2017, 2018 and 2019 before all network upgrades identified in the cluster study are installed in 2020. It is inefficient for an Interconnection Customer to accelerate capital investment for a 2017 provisional interconnection, for example, only to find that expected levels of energy injection and sales cannot occur because of congestion and thus frequent curtailment. Timely information about the extent of potential congestion on relevant transmission lines through an operational assessment that considers expected levels of committed generation, transmission and load during 2017, 2018 and 2019, for example, is needed. Generation developers should not be hampered in making informed investment decisions when there is an ability to provide needed information and increase market transparency. If the operational assessment shows that interconnection in any of 2017, 2018 or 2019 would provide limited interconnection service and thus the more effective approach is to

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<sup>62</sup> See MISO BPM 015, section 6.2.9.

wait to connect until 2020 when all network upgrades are completed, then that is a decision Interconnection Customers can make based on study results. The current GIPs force the Interconnection Customer to make these decisions blindly.

Last, the Transmission Provider should be required to provide information about projects that are in suspension. Whether or not suspended projects are in or out of suspension impacts the level of congestion and potential curtailment. An Interconnection Customer cannot attempt to properly forecast expected injection levels and power sales when information about the ability of suspended projects to come on line and compete for existing capacity is not known. The Interconnection Customer cannot control when or if another project might come out of suspension, but at least it will be aware of the potential impact and can plan accordingly. AWEA members have asked for suspension information from RTOs, such as SPP, but been denied. There is no reason why this type of information should not be transparent and provided in a way that enables an Interconnection Customer to assess whether, based on the location and kV connection point, the project might have an impact on its ability to inject energy. Project suspension information will also enable an Interconnection Customer to gauge its exposure to additional network upgrade costs trickling down from a higher-queued (but suspended) project. Again, AWEA members have asked for such information, but been denied.

Accordingly, AWEA urges the Commission to find that the lack of transparency and availability of congestion information is unjust and unreasonable and inhibits the efficient development of generation and thus to amend the *pro forma* GIPs to:

- require the Transmission Provider to post information monthly on congested transmission facilities and interfaces regardless of voltage level, including flow duration curves, the number of hours of Transmission Provider-ordered generation curtailment due to congestion on that facility or interface, and the cause(s) of the congestion (such as a contingency or an outage);

- require the Transmission Provider to provide information in interconnection studies that addresses existing usage and congestion and projected usage and congestion on the transmission facilities that are electrically significant to the Interconnection Customer's project based on system conditions known at the time; and
- require the Transmission Provider to post project suspension information including location, point of interconnection and date suspension was initiated.

**iii. The GIPs Should Allow an Interconnection Customer to Use its Interconnection Capacity through Two or more Phases, and in Two or More GIAs, and Provide for Full Reimbursement if the Capacity is Terminated and Sponsored Upgrades are Used by Another Customer**

A generation developer needs the ability to flexibly manage the capacity under its GIA. This includes allowing the developer to divide the capacity under an interconnection request into separate GIAs. Also, if the developer does not ultimately use all the capacity under a GIA, and Transmission Provider rules require that the capacity be reassigned, then the developer should be compensated if the upgrades it paid for are used by another customer. The *pro forma* GIPs should be reformed to remedy these separate but related issues.

First, when a developer submits an interconnection request it often does not know how much of the energy from its project will be sold under a PPA or when a PPA might be executed. For example, a developer may have identified a location for a generation project, and arranged for sufficient land leases to accommodate a 300 MW project. However, when the developer submits its request to interconnect this project to the applicable Transmission Provider, which is one of the first steps in the development process, it rarely will have PPAs for the full output of the project. Even when the developer executes the GIA, it may still lack PPAs to cover the full output of its project. However, the developer will pay the costs of network upgrades required under the GIA to accommodate the full MW capacity. Later, through participation in utility RFPs, the developer may arrange to sell 200 MW to one utility, for example, and retain control of the other 100 MW in hopes of selling that output to another utility or market participant at a

later date. For this scenario to work optimally for the developer, it needs flexibility in contract management and timing, and protection for the costs of its investment.

The developer would benefit from being able to split its GIA into more than one agreement when not all capacity is covered by one PPA. In the example above, the developer should be allowed to split the GIA into two GIAs at the same location, so that the 200 MW has its own GIA, and the 100 MW a separate GIA. This way, each project company would have a separate GIA and separate PPA, which helps facilitate project financing as more streamlined interconnection arrangements and quality project documents demonstrate to lenders a lower level of project risk.

Some Transmission Providers have, however, used practices that make it difficult for developers to use their interconnection capacity in this manner. Only some FERC-jurisdictional Transmission Providers (such as PJM) have allowed splitting a GIA once it is signed. (ERCOT also allows this practice.) But based on AWEA's members' experience, Transmission Providers such as MISO, CAISO, and SPP and in the Western Interconnection have not allowed an Interconnection Customer to split its GIA. Instead, the developer is typically forced to enter into customized secondary agreements to share the capacity between the projects. This requires negotiation of agreements that complicate interconnection arrangements, requests for various waivers from the Commission, and may put one Interconnection Customer in the role of being a service provider to a second generator, which is far from optimal. The authorizations may become even more complicated if non-affiliates are involved. Such arrangements complicate both operational issues and project financing, and raise various unnecessary compliance risks for various parties to these arrangements. So long as all reliability and operational issues are appropriately addressed, and cost responsibility is accounted for so that the Transmission

Provider and transmission owner do not incur risks of not recovering costs, there appears to be no valid reason why a GIA cannot be split. Indeed, the fact that PJM already allows this shows that any reliability, operational and costs issues can be addressed.

Allowing an Interconnection Customer to split its GIA is consistent with Commission practice in several other related areas. Transmission customers are allowed to permanently assign to other customers a portion of transmission service they receive under an OATT. Interstate gas pipeline customers likewise have this right. The same right should be granted to Interconnection Customers.

On a related note, in cases when a developer will not use the capacity under a GIA, it should have the right to a reimbursement from the entity that does eventually use the upgrades that the Interconnection Customer funded under its GIA. However, Transmission Providers have become more aggressive in seeking to terminate unused capacity from GIAs, and the Commission has not required that the Interconnection Customer be reimbursed for its costs when another user benefits from the upgrades paid for by the relinquishing Interconnection Customer. This is not just and reasonable. One RTO, SPP, has attempted to address this by providing the Interconnection Customer transmission credits when capacity it has previously paid for, but has not put into commercial operation for three years, is terminated from its GIA.<sup>63</sup> Transmission credits may be appropriate when the Interconnection Customer is actually using the capacity, but it is inadequate compensation when the Interconnection Customer has been forcibly deprived of, or otherwise relinquishes use of, the capacity in order to benefit another party. In such cases, the beneficiary should reimburse the original Interconnection Customer for the costs correlating to the capacity.

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<sup>63</sup> *Southwest Power Pool, Inc.*, 147 FERC ¶ 61,201 (2014).

In order to address this situation, the Commission should amend the *pro forma* GIPs to:

- allow an Interconnection Customer to split its GIA resulting in the creation of one or more additional GIAs; and
- ensure that assignments or termination of capacity under GIAs, including those initiated by the Transmission Provider, lead to the reimbursement to the Interconnection Customer of the payments it made for network upgrades from appropriate beneficiaries that use the capacity.

**C. Reforms to Improve Certainty of Network Upgrade Costs**

**i. The Costs for Interconnection Facilities and Network Upgrades Should be Capped at Stated Accuracy Margins Absent Extraordinary Circumstances beyond the Transmission Provider’s Control**

The Commission’s policy allows the Transmission Provider to provide a good faith estimate of the cost of network upgrades needed to accommodate the level of interconnection service. The cost estimate listed in the GIA can include typically a +/- 20% accuracy margin.<sup>64</sup> Then, within months after commercial operation, a true-up is undertaken where an additional charge is assessed to the Interconnection Customer if the actual cost of the identified interconnection facilities and network upgrades exceeds the initial estimated amounts stated in the GIA.

The application of the accuracy margins needs more certainty. The Commission should clarify that, absent demonstrated extraordinary circumstances outside the control of the Transmission Provider, the stated accuracy margin is a cap on the amount of additional cost that may be assessed to the Interconnection Customer for interconnection facilities and network upgrades. This is consistent with the Commission’s determination in Order No. 2003-A: “[W]e are not removing the accuracy margins for cost estimates. Margins are helpful because they give the Interconnection Customer some level of certainty with respect to its cost exposure.”<sup>65</sup>

<sup>64</sup> See Commission *pro forma* GIP, section 8.3.

<sup>65</sup> Order No. 2003-A at P 173.

Otherwise, costs can increase, creating a large amount of risk for the Interconnection Customer who needs to make business decisions based on the expected interconnection facilities and network upgrade costs provided by the Transmission Provider and stated in the GIA. Further, the Interconnection Customer must be able to provide a reasonable estimate of those costs to financing institutions and private equity. Certainty is needed, and this is achievable, since, as discussed above, CAISO already provides these estimates. PTOs annually publish their per unit cost for facilities generally required for interconnection and from this an Interconnection Customer's allocated network upgrade cost is determined and capped in the Phase I study process.

A Transmission Provider should not be able to assess costs beyond the allowed accuracy margin. A balanced standard is needed in which the Transmission Provider is given full latitude to provide an estimate of its costs, and the Interconnection Customer is obligated for final prudent costs up to the allowed accuracy margin. The Transmission Provider would be obligated for the portion of any final cost beyond the allowed accuracy margin, excluding demonstrated extraordinary costs incurred beyond its control. The burden would be on the Transmission Provider to accurately estimate its costs. This is reasonable because the Transmission Provider alone is in control of deriving its estimate. In turn, it is reasonable for the Transmission Provider to bear responsibility for its own inaccurate cost estimates. Likewise, it is unjust and unreasonable for the Transmission Provider to shift the consequences of its inaccurate cost estimates to the Interconnection Customer. The risk should stay with the party that has control of the process.

Further, the Transmission Provider should be required to provide a line item estimate of the charges comprising the overall estimate for each interconnection facility and network



upgrade. For example, a project might require separate upgrades to a transmission line, a substation and switches. Line item cost components should be provided to the Interconnection Customer for each separate facility. Some Transmission Providers will not provide such detail and will only provide a lump-sum estimate. This lack of transparency is not just and reasonable. There have been instances in which line item cost components were transparent, and the Commission therefore had the opportunity to order proposed line item charges removed, which lowered Interconnection Customers' costs and in turn rates for the sale of electric power to consumers.<sup>66</sup> This would not have been possible if the lump-sum, non-transparent approach had been followed.

Last, the Commission should clarify that the accuracy margin percentage applies on a per interconnection facility and network upgrade basis and not to the overall cost of these facilities. Otherwise, a Transmission Provider could reallocate costs within an overall estimate to stay within the accuracy margin, rather than apply a more disciplined cost estimate to each cost item.

Accordingly, AWEA requests that the Commission amend the *pro forma* GIPs to:

- require the Transmission Provider to list an accuracy margin of no more than 20% in its GIP;
- require the Transmission Provider to include that accuracy margin in the appropriate early study report and in the GIA;
- require the Transmission Provider to provide line item charge estimates for each interconnection facility and network upgrade;
- provide that, for the true-up, the Interconnection Customer shall be obligated to pay no more for each interconnection facility and network upgrade than the good faith estimate up to the accuracy margin unless the Transmission Provider can demonstrate the existence of extraordinary circumstances beyond its control causing the increased costs; and

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<sup>66</sup> See *Midwest Indep. Transmission Sys. Operator, Inc.*, 135 FERC ¶ 61,222 at PP 46-52 (2011).

- require the Transmission Provider to apply the accuracy margins individually to each interconnection facility and network upgrade facility and not on an aggregate basis to all such facilities.

**ii. The GIPs Should Require the Interconnection Customer’s Agreement for the Interconnecting Transmission Owner to Self-Fund Network Upgrades**

The current *pro forma* GIPs provide two ways to fund network upgrades: the Interconnection Customer provides 100% of the up-front funds (defined herein as “IC Funding”) or the Transmission Provider provides 100% of the up-front funds (“Self-Funding”). The issue of self-funding is significant as it can impose material costs on the Interconnection Customer and ultimately consumers.

The Commission’s *pro forma* GIPs also provide that the Interconnection Customer will, when it funds the upgrades, be reimbursed 100% either in cash or as a credit against transmission service. Some RTOs, such as ISO-NE, MISO and PJM, have been granted a variation so the Interconnection Customer receives no reimbursement.<sup>67</sup> Under this approach, the Interconnection Customer’s cost for the network upgrade portion of interconnection service is 100% of the cost of the network upgrades.

In *Hoopeston*,<sup>68</sup> the Commission allowed the interconnecting transmission owner to recover a “return of and on” the amount it provides for Self-Funding of the network upgrades and to recover a revenue requirement of that amount over 30 years. Thus, the Interconnection Customer will pay much more than 100% of the cost of the network upgrade portion of the interconnection service, *i.e.*, the cost under IC Funding.<sup>69</sup>

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<sup>67</sup> MISO provides a 10% reimbursement of network upgrade costs for facilities rated at 345 kV or higher.

<sup>68</sup> See *Midcontinent Indep. Sys. Operator, Inc.*, 145 FERC ¶ 61,111 (2013), *reh’g pending* (“*Hoopeston*”).

<sup>69</sup> The level of cost increase to the Interconnection Customer will vary from transmission owner. In *Hoopeston*, the transmission owner decided to recover the funded amounts over a 30-year period, applying a fixed charge rate of at least 12.28%, which turned the \$1 million in network upgrade costs to over \$3.6 million to be paid

The choice of whether IC Funding or Self-Funding will be charged rests solely with the interconnecting transmission owner. The interconnecting transmission owner decides whether the Interconnection Customer pays only as much as 100% of the cost of the network upgrades or much more over time through Self-Funding.

It is unjust and unreasonable and unduly discriminatory for the Self-Funding decision to remain with the transmission owner.<sup>70</sup> First, the transmission owner would not have the opportunity to increase its earnings through a return on its investment if the Interconnection Customer had not sought to interconnect to its system. Second, the transmission owner may not be an independent entity and could exercise that choice in a way to favor its or its affiliate's new generation projects. Thus, there is the opportunity for undue discrimination and affiliate abuse.

In Order No. 2003 the Commission held:

The Commission remains concerned that, when the Transmission Provider is not independent and has an interest in frustrating rival generators, the implementation of participant funding, including the 'but for' pricing approach, creates opportunities for undue discrimination . . . [A] number of aspects of the 'but for' approach are subjective, and a Transmission Provider that is not an independent entity has the ability and incentive to exploit this subjectivity to its own advantage. For example, such a Transmission Provider has an incentive to find that a disproportionate share of the costs of expansions needed to serve its own power customers is attributable to competing Interconnection Customers. *The Commission would find any policy that creates opportunities for such discriminatory behavior to be unacceptable.*<sup>71</sup>

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out by the Interconnection Customer over time. When the network upgrade cost basis reaches into the tens of millions of dollars, the impact on Interconnection Customer will increase exponentially.

<sup>70</sup> See *Midcontinent Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61, 220 at P 48 (2015) (transmission owner "unilaterally electing to initially fund network upgrades where the interconnection customer is held responsible for such costs and does not receive credits to reimburse it for those costs, . . . may deprive the interconnection customer of other options to finance the cost of the network upgrades that provide more favorable terms and rates" and "it stands to reason that the interconnection customer would have the incentive to find the lowest cost solution to funding network upgrades associated with its interconnection requests, and therefore the transmission owner should not have control over the interconnection customer's funding decision.").

<sup>71</sup> Order No. 2003 at P 696 (emphasis added).

Third, Self-Funding affects competition. The Interconnection Customer that is subject to IC Funding pays no more than 100% of the cost of network upgrades to obtain interconnection service, whereas the Interconnection Customer subject to Self-Funding pays much more than 100% of the cost of the network upgrades to obtain interconnection service. The ability to require one Interconnection Customer to pay more through Self-Funding subjects similarly-situated customers to different rates without justification and thus is unduly discriminatory.<sup>72</sup> This is particularly true where Interconnection Customers compete in the same RTO market (or neighboring RTO markets), for example, but one interconnecting transmission owner chooses to allow IC Funding and the neighboring interconnecting transmission owner chooses Self-Funding. Interconnection Customers should be subject to the same cost policies.

Accordingly, the Commission should find that allowing the interconnecting transmission owner alone to choose the Self-Funding option no longer is just and reasonable and is unduly discriminatory and should amend the *pro forma* GIPs to:

- allow Self-Funding only where chosen by the Interconnection Customer and where the Transmission Provider or interconnecting transmission owner, as applicable, agree to do so.

**iii. The GIPs Should Provide a Consistent Process and Methodology for the Cost of Network Upgrades to Restore Interconnection Service Capacity**

An Interconnection Customer that chooses ERIS pays for network upgrades to accommodate an injection of energy that often is less than the MW nameplate capacity of its generating facility. The Commission's current GIPs allow the ERIS customer to inject as much as 100% of its energy so long as there is as-available interconnection capacity. This model can be well suited for generation facilities such as wind energy generators that do not continually

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<sup>72</sup> See *St. Michaels Municipal Utils. Comm'n v. FPC*, 377 F.2d 912 (4th Cir. 1967); see also *Cities of Newark, DE v. FERC*, 763 F.2d 533 (3rd Cir. 1985).

produce power at full nameplate capacity, as they will pay for only those network upgrades needed to accommodate their likely energy production. Generators are able to sell energy at a lower cost because they forgo funding network upgrades as would be required for NRIS. (Although, as discussed above, some RTOs require the generator to pay for network upgrades based on 100% MW nameplate ERIS in the off-peak, and such dispatch assumptions should be substantiated.) However, as more projects come on line, the as-available capacity begins to diminish, which, in turn, limits the ability to inject energy. Projects face curtailment and this reduces revenue.

Unfortunately, often Transmission Provider OATT transmission planning processes do not provide means for transmission upgrades to relieve congestion and address these economic needs. AWEA is aware that the Commission is considering whether certain Transmission Provider planning should be revised to address these economic needs, such as through lowering the voltage threshold for economic planning and regional cost allocation.<sup>73</sup> AWEA encourages the Commission to consider broadening this assessment to all regions of the United States so that latent benefits for consumers can be realized. In the meantime, having no other option, many operating generation projects have approached the Transmission Providers in various regions to ascertain what system upgrades would be needed to restore the as-available capacity and have paid to put such additional network upgrades in place. The processes Transmission Providers employ in responding to these requests, however, are not formalized or consistent. MISO, for example, has entered into a three-party agreement among itself, the transmission owner and the Interconnection Customer.<sup>74</sup> MISO also has done the opposite and allowed an agreement to be

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<sup>73</sup> See, e.g., the proceeding in Docket No. EL13-88-000, *supra* n. 64.

<sup>74</sup> See *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER14-287-000, Delegated Letter Order issued Dec. 20, 2013.

solely between the Interconnection Customer and transmission owner.<sup>75</sup> PJM, on the other hand, has consistently used the three-party route.<sup>76</sup>

The costs of these network upgrades to the Interconnection Customer also are inconsistent. Some Transmission Providers will follow the Commission's *pro forma* GIPs model and charge only actual cost plus applicable tax gross up.<sup>77</sup> Other Transmission Providers treat these system upgrades differently from generator interconnection network upgrades and pursue a full blown revenue requirement that includes a rate of return, operating and maintenance (O&M) expense, common and general (C&G) expense, depreciation and taxes.<sup>78</sup> The Commission should act to bring uniformity to the process and the cost.

An Interconnection Customer in this situation is simply seeking to restore as-available interconnection service capacity. It wishes to be able to continue to inject energy on an as-available basis as was intended when its project was initially studied and the GIA signed, without being curtailed. Yet, even this is not guaranteed because it only frees up capacity on an as-available basis. As such, the Transmission Provider has taken the position that there is no guarantee that the Interconnection Customer will not again be curtailed in the future.<sup>79</sup>

In essence, the network upgrades are not substantially different than the network upgrades originally identified as being needed in the GIA. The only difference is the passage of

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<sup>75</sup> See *Northern Indiana Pub. Serv. Co.*, Docket No. ER12-710-000, Delegated Letter Order issued Jan. 19, 2012; see also *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER14-1315-000, Delegated Letter Order issued Mar. 31, 2014 (“*MISO TUA*”).

<sup>76</sup> See *PJM Interconnection, L.L.C.*, Docket No. ER13-1029-000, Delegated Letter Order issued Apr. 12, 2013.

<sup>77</sup> See *id.*; *Ameren Servs. Co.*, Docket No. ER09-1683-000, Delegated Letter Order issued Oct. 22, 2009; *Ameren Servs. Co.*, Docket No. ER10-1701-000, Delegated Letter Order issued Aug. 9, 2010; *ITC Midwest LLC*, Docket No. ER11-4159-000, Delegated Letter Order issued Sept. 22, 2011; *ITC Midwest LLC*, Docket No. ER11-4146-000, Delegated Letter Order issued Sept. 21, 2011.

<sup>78</sup> *Supra* n. 80.

<sup>79</sup> *See id.*

time and the installation of additional competing generation or other uses requiring the need for further network upgrades. The cost methodology for those network upgrades should be the same as applies to all other network upgrades for Interconnection Customers seeking ERIS, or NRIS for that matter: actual cost plus any applicable tax gross up. The Commission's *pro forma* GIP policy does not allow the Transmission Provider to also charge a rate of return, O&M expense, C&G expense, depreciation and taxes. Indeed, the Commission's *pro forma* GIA allows the Transmission Provider to collect an O&M charge only on the Transmission Provider's interconnection facilities, but not network upgrades.<sup>80</sup>

Uniformity also is needed because one Transmission Provider may charge only actual cost plus applicable tax gross up, whereas a neighboring Transmission Provider may charge a rate of return, O&M expense, C&G expense, depreciation and taxes. The Interconnection Customer taking interconnection service from the second Transmission Provider will pay much more and be at a competitive disadvantage compared to an Interconnection Customer taking service from the first Transmission Provider. These Interconnection Customers compete against each other. This allows an unduly discriminatory arrangement among similarly-situated customers.<sup>81</sup>

Accordingly, the Commission should find that an Interconnection Customer's desire to fund new network upgrades to restore interconnection service capacity is a necessary part of the GIP, and that a uniform process and policy to fund such network upgrades is just and reasonable and necessary to ensure that processes are not unduly discriminatory or preferential. To effectuate this, the Commission should amend the *pro forma* GIPs to:

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<sup>80</sup> See Commission's *pro forma* GIA, section 10.5.

<sup>81</sup> See *Dynegy Midwest Generation, Inc. v. FERC*, Feb. 11, 2011, Case No. 09-1306 (D.C. Cir. 2011).

- provide an express right for an Interconnection Customer to fund network upgrades intended to provide further injection capacity as part of ERIS or NRIS, as desired;
- provide that the cost for such network upgrades shall be no more than actual cost capped at the stated accuracy margin plus any applicable tax gross up; and
- provide that any agreement addressing payment for such network upgrades must be with the Transmission Provider providing the interconnection service.

**iv. Interconnection Customers Should be Compensated for Network Upgrades that Benefit Other Interconnection Customers and Network Users**

AWEA encourages the Commission to apply the principle that, if an Interconnection Customer funds network upgrades that benefit other parties, whether a later-queued interconnection customer, or another network user, the Interconnection Customer should be compensated by the beneficiary. This approach is consistent with the Commission's use of the beneficiary-pays cost allocation principle required for transmission planning under Order No. 1000, and also serves to minimize free ridership in the interconnection process.

One application of this principle is in MISO's GIPs, which provide that, if an Interconnection Customer funds a network upgrade and a later-in-time Interconnection Customer benefits from that network upgrade, the Interconnection Customer that funded the network upgrade will receive compensation toward the cost from the later-in-time Interconnection Customer. MISO and other filing parties explained that without such contributions, interconnecting generators confront a "first mover/free rider" problem, as only the first party to interconnect must pay, and subsequent generators use their upgrades at no additional charge.<sup>82</sup>

The Commission should require those RTOs and Transmission Providers that do not already do so to include "shared network" compensation in their GIPs as a best practice. This

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<sup>82</sup> See *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,221 at P 55 (2010) ("*MISO*") (we "find that Filing Parties' proposal to share the costs of Shared Network Upgrades among first-moving and later-coming generators is just and reasonable.").



will ensure that the funding Interconnection Customer is compensated for its investment from other generators that benefit. This will encourage such investments, as the Interconnection Customer has a higher likelihood of potential reimbursement from another Interconnection Customer.

Likewise, the Commission should extend this concept to any Interconnection Customer-funded network upgrades that occur after a project's commercial operation date, such as to restore levels of ERIS, as discussed above. Existing Interconnection Customers with operational generation have funded such upgrades only to have later-in-time new Interconnection Customers lean on, and thus benefit from, those upgrades for their upcoming generation project, but without providing any reimbursement to the funding Interconnection Customer. Such network upgrades are needed in furtherance of interconnection service for the existing operational and new Interconnection Customers. It is just and reasonable to assign a portion of the cost to applicable new Interconnection Customers, consistent with *MISO*.<sup>83</sup> Without this revision, the funding Interconnection Customer is subject to a double hit: paying for all of the cost of the network upgrade; a reduction in ERIS (which is the reason that it funded the additional network upgrades) because the applicable later-in-time Interconnection Customers utilize that capacity.

Further, the Commission should extend this concept to other system users that benefit from the upgrades. In *MISO TUA*, for example, several operating generators funded post-operational upgrades to 138 kV transmission lines. Evidence before the Commission shows that all users of the integrated grid benefit from those upgrades.<sup>84</sup> Indeed, two regional transmission

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<sup>83</sup> See *id.*

<sup>84</sup> See *Northern Indiana Pub. Serv. Co. v. MISO*, Complaint of Northern Indiana Public Service Company, Docket No. EL13-88-000, Sept. 9, 2013, at 33 (identifying a certain 138 kV upgrade paid for by generators that should have been included in MISO transmission planning and approved for cross-border transmission purposes with PJM and would have brought benefits to system users).

owners stated that these generators “should be commended for helping to relieve congestion without charging ratepayers.”<sup>85</sup> Such upgrades provide benefits to system users in the form of lower LMP and alleviated redispatch and market-to-market costs. Yet, system users do not pay for these benefits contrary to the beneficiaries pay concept. The Commission should correct this imbalance.

Accordingly, AWEA urges the Commission to find that the current method of reimbursement for funded network upgrade costs is unjust and unreasonable and thus amend its *pro forma* GIPs to:

- require the Transmission Provider to adopt a methodology and process that will require an applicable later-in-time Interconnection Customer and other system user to provide compensation to an Interconnection Customer that funded a network upgrade for which an applicable later-in-time Interconnection Customer and other system user benefits.

#### **D. Reforms to Improve Accountability in the Interconnection Process**

##### **i. The Transmission Provider Should be Accountable through Liquidated Damages if It Fails to Provide Timely or Accurate Interconnection Study or Restudy Results or List a Contingent Facility**

AWEA believes that the accuracy of the interconnection process has been hampered by the lack of accountability in the GIPs for Transmission Providers. If Interconnection Customers fail to comply with the requirements of the GIPs or GIA they are subject to consequences under the GIPs, including being ejected from the queue for failing to execute various interconnection study agreements or to provide study deposits by designated timelines, and also forfeiting payments made to the Transmission Provider. The Commission has accepted Transmission

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<sup>85</sup> *Northern Indiana Pub. Serv. Co. v. MISO*, Reply Comments Of American Electric Power Service Corporation And Exelon Corporation, Docket No. EL13-88-000, Apr.15, 2015, at 9.

Provider arguments that such Interconnection Customer requirements are needed to keep the interconnection process running efficiently and timely.<sup>86</sup>

As discussed above, there is a need for greater accuracy and timeliness in interconnection studies. However, requiring the Transmission Provider to provide timely and accurate study results, without added incentive, will not by itself be effective. It is just and reasonable for the Transmission Provider to bear the consequences of any failure to provide accurate and timely interconnection study results – which is within its control – instead of passing through all these costs to the Interconnection Customer.

By analogy, a Transmission Provider faces consequences if it fails to comply with NERC Reliability Standards. The potential financial consequences for failing to abide by NERC requirements are and have been a significant incentive to comply. There is no reason why that Transmission Provider should not be faced with a similar compliance incentive with the GIPs. The Commission does not exempt RTOs from being assessed NERC penalties, and decided it would disallow the automatic pass-through of NERC penalties assessed to an RTO:

Although RTOs and ISOs have raised legitimate concerns regarding their not-for-profit status and potential ambiguities in defining the responsibility for certain violations, ***we are concerned that RTOs and ISOs will not have the appropriate incentives to proactively comply with Reliability Standards if they have blanket authority to automatically pass through monetary penalties to their customers.***<sup>87</sup>

The Commission stated that there are ways for the RTO to avoid such penalties:

For instance, RTO/ISO boards of directors and management may incorporate policies for planning and operation of the bulk power system in compliance with Reliability Standards as a significant part of the RTO/ISO staff and management performance evaluations and compensation programs, as part of an effective

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<sup>86</sup> See cases referenced *supra* in note 14,.

<sup>87</sup> *Reliability Standard Compliance and Enforcement in Regions with Regional Transmission Organizations or Independent System Operators*, Order Providing Guidance on Recovery of Reliability Penalty Costs by Regional Transmission Organizations and Independent System Operators, 122 FERC ¶ 61,247 at P 16 (2008) (emphasis added).

internal compliance program. Bonuses and other incentives received by senior management could also be made contingent on penalty-free operations. Such practices could substantially lessen the likelihood of employee and/or management behavior that results in violations.<sup>88</sup>

The same rationale should apply for the GIPs, which are, after all, reliability studies. If a Transmission Provider contracts for the services of a third-party contractor or transmission owner to perform the studies, the Transmission Provider could include contract terms with that third-party contractor or transmission owner that specifies the due date, an accuracy requirement, and includes indemnification and other provisions to keep the Transmission Provider harmless from consequences if the study is late or inaccurate. Alternatively, the Transmission Provider can perform the studies in-house with its own staff and manage the risk itself, with employee bonus incentives as the Commission noted above.

Instead of continuing to require Interconnection Customers to bear the brunt of delayed and inaccurate studies, appropriate financial consequences should be assessed to the Transmission Provider through assessment of liquidated damages. Such financial consequences would mitigate damages Interconnection Customers incur through delayed and inaccurate studies. Ultimately, holding Transmission Providers accountable for not complying with their own GIPs will incent them to improve their performance and maintain compliance with their regulatory obligations.

Assessment of liquidated damages is already provided for in the GIPs, as the Commission has already exposed a Transmission Provider to some of the costs of delays in the interconnection process. The *pro forma* GIA imposes a financial consequence on the Transmission Provider if it fails to complete any portion of its interconnection facilities or network upgrades by the dates specified in the GIA. Section 5.3 states that the Interconnection

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<sup>88</sup> *Id.* at P 26.

Customer's actual damages resulting from such Transmission Provider failure may include "fixed operation and maintenance costs and lost opportunity costs." Because the amount of such damages are "uncertain and impossible to determine at this time," the Interconnection Customer is provided with liquidated damages "equal to ½ of 1 percent per day of the actual cost of the Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct." The liquidated damages are capped at "20 percent of the actual cost of the Transmission Provider Interconnection Facilities and Network Upgrades for which the Transmission Provider has assumed responsibility to design, procure, and construct."

AWEA submits that, if liquidated damages are appropriate when a Transmission Provider does not complete interconnection facilities and network upgrades on time, liquidated damages are also appropriate when the Transmission Provider fails to complete interconnection studies on time. Both actions and responsibilities of a Transmission Provider represent delays that harm the efficient and cost-effective development of new generation.

Increased use of liquidated damages beyond just delays in construction has previously been considered by the Commission. In the Order No. 2003 rulemaking proceeding, the Commission initially proposed a liquidated damages provision in the GIPs to address a Transmission Provider's failure to complete interconnection studies on time, proposing "1% of the actual costs of the applicable study cost per day, . . . not [to] exceed 50% of the actual cost of the applicable study." The Commission ultimately decided against the provision, stating:

We are eliminating liquidated damages from the Final Rule LGIP. While we understand the value of providing an incentive to complete Interconnection Studies, we are concerned that the availability of such a provision may undermine the Transmission Provider's ability to economically administer its study process.

Moreover, we question whether liquidated damages are appropriate during the study phase, since at that time it will be unclear whether a prospective Interconnection Customer intends to pursue its Interconnection Request. Because at this stage the prospective Interconnection Customer does not face a substantial risk of damages, we are not standardizing liquidated damages for Transmission Providers during the study phase (i.e., in the Final Rule LGIP). Rather, we are requiring that a Transmission Provider use due diligence to perform within a specified time period. . . .<sup>89</sup>

In the intervening years since that order, the situation has changed. The Commission has approved substantially higher deposits, including non-refundable payments, and other obligations on the Interconnection Customer to ensure it is committed to its interconnection request. There are now substantial risks for the Interconnection Customer. And as discussed above, the “due diligence” or “reasonable efforts” standard has proven ineffective in ensuring that studies and restudies are consistently completed on time. Transmission Providers have amassed considerable experience at performing interconnection studies and should be held to a higher standard of performance, with appropriate consequences for failing to comply with their GIPs.

Moreover, the Commission has already authorized assessment of operational penalties against Transmission Providers for delayed completion of studies. In Order No. 890,<sup>90</sup> the Commission determined that, to increase the transparency and expediency of transmission service processing, Transmission Providers could be subject to operational penalties when they fail to use due diligence to process transmission studies within the timelines required by the OATT.<sup>91</sup> In reaching this conclusion, the Commission rejected various arguments by

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<sup>89</sup> Order No. 2003 at PP 898, 899.

<sup>90</sup> *Preventing Undue Discrimination and Preference in Transmission Servs.*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g and clarification*, (“Order No. 890-A”), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) (codified at 18 C.F.R. pts. 35, 37).

<sup>91</sup> Order No. 890 at PP 1319, 1340-54.

Transmission Providers, including that imposition of penalties would violate due process, or that firm deadlines were unworkable or could lead to reliability concerns.<sup>92</sup> As is it did regarding delays in transmission studies, the Commission should likewise recognize that delays in completing interconnection studies should subject Transmission Providers to financial consequences.

Finally, some Transmission Providers may contend that paying liquidated damages would deprive them of their right to recover their costs, as costs of paying liquidated damages might not be passed to ratepayers. However, the Commission could conclude that, to the extent Transmission Providers have failed to comply with the obligation under their OATTs to provide accurate and timely interconnection studies, then they have not prudently incurred costs in performing such studies. It is not reasonable to exempt a Transmission Provider from the consequences of failing to comply with its OATT obligations. The Commission could find that in given circumstances a Transmission Provider is not acting prudently – and should not be able to recover its full costs – when it violates its OATT. As a consequence, it is not unreasonable to subject Transmission Providers to the possibility of liquidated damages for non-compliance with the timeliness and accuracy requirements in their OATTs. And, as noted above, the Commission's *pro forma* GIA already exposes Transmission Providers to liquidated damages.

Transmission Providers have acquired substantial experience in performing interconnection studies and should be held to a higher level of performance. It is therefore appropriate to adopt the Commission's original proposal of liquidated damages at 1% per day for late performance of studies – which ultimately is just a refund to the Interconnection Customer of the amounts it owes under the GIPs. However, there should not be a 50% cap on damages for

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<sup>92</sup> *Id.* at P 1327.

late study results as the Commission initially proposed. At 1% per day, the 50% cap would be reached in 50 days and study delays have been much longer than 50 days. As such, Transmission Providers would not have a full incentive to avoid additional delays and complete the applicable study. Liquidated damages of 1% per day with no cap would provide the incentive for study delays to be as short as possible. This, in turn, would support the efficient development of new generation.

Liquidated damages are also appropriate when a Transmission Provider's study results prove inaccurate. The Interconnection Customer may have incurred additional costs to proceed to the next study phase, committed capital to develop the project, and exposed itself to damages for non-performance in other commercial arrangements with third parties, all based on the extent of the network upgrade costs that the Transmission Provider identified in the now erroneous study. If the study must be redone and the Interconnection Customer decides not to continue with the project because of increased, unexpected network upgrade costs, the Transmission Provider should pay the Interconnection Customer liquidated damages equal to 20% of the cost of interconnection facilities and network upgrades identified in the initial study or as listed in the GIA. The amount of damages to the Interconnection Customer cannot be measured, and thus the 20% standard, such as already is included in section 5.3 of the GIA, is appropriate. If the Interconnection Customer decides to continue with its project after the study re-do, even though there are unexpected increased costs, the Interconnection Customer should receive liquidated damages equal to 20% of the actual cost of the new or additional network upgrade costs identified in the new study. The 20% standard provides a reasonable balance. The Transmission Provider is held accountable for its actions. The Interconnection Customer pays for 80% of the increased network upgrade cost (similar to how section 5.3 of the GIA also requires the



Interconnection Customer to pay up to 80% of the costs of facilities in the event of delays). These liquidated damages provisions will support the development of new generation. They ensure that the risk of the Transmission Provider's role in performing the studies is not shifted to the Interconnection Customer who has no role in performing the studies and has no means to guard against the cost risk and the commercial implications for its project. Of course, the Transmission Provider can avoid all liquidated damages by simply providing accurate study results.

Finally, as discussed above, the Commission requires a Transmission Provider to list contingencies in studies and the GIA so the Interconnection Customer is aware of the potential need and cost. If the Transmission Provider fails to identify a contingent facility that may be required for interconnection service and the GIA becomes effective under the FPA without that contingent facility being listed, the Interconnection Customer should not be required to bear the full consequence of any additional cost for any further or reconfigured network upgrades. The Interconnection Customer will have proceeded with the project and entered into business arrangements based on the potential cost of network upgrades (and contingencies) listed in its GIA. The Interconnection Customer will be harmed financially both from the additional network upgrade cost and any resulting delay while additional network upgrades are constructed. Moreover, its project pro forma commercial statements will be impacted, as well as any PPA or sales arrangement. The amount of that harm will be uncertain.

As liquidated damages, the Transmission Provider should be required to bear 20% of the final, actual cost of any additional or changed network upgrades. This 20% figure corresponds to the 20% amount that already is in section 5.3 of the Commission's *pro forma* GIA as discussed above. The Interconnection Customer would be responsible for the other 80%

following the section 2.3 construct. The imposition of this liquidated damages requirement is just and reasonable because the ability to list all necessary contingencies is a matter wholly within the Transmission Provider's control. So long as the Transmission Provider performs thorough interconnection studies and identifies all potential contingencies in the facilities study and GIA, it will never be subjected to this cost potential. The Interconnection Customer needs accurate potential cost information as it makes investment decisions and has no means to protect itself from this unexpected cost.

Accordingly, for these reasons, AWEA urges the Commission to modify the *pro forma* GIP and GIA, as applicable, to provide:

- if the Transmission Provider fails to provide final study results, for any study or restudy, by the applicable dates listed in its GIP to the Interconnection Customer, the Transmission Provider shall pay to the Interconnection Customer an amount equal to 1% of the actual cost of any such study or restudy per day for each day such study or restudy results are late, until it has refunded all study costs;
- if a study or restudy error is found after final study or restudy results are provided and confirmed to the Interconnection Customer, and the Transmission Provider decides it must re-perform the study or restudy, the Transmission Provider shall not charge the Interconnection Customer for any of the costs of the study or restudy that the Transmission Provider must re-perform;
- if a study error is found and if the re-performed study or restudy occurs after the facilities study was performed and communicated as final (but before the GIA is executed or filed unexecuted with the Commission), and identifies the need for changed, different or additional network upgrades in order to provide the level of interconnection service listed in the interconnection request, with increased cost, the Transmission Provider shall pay liquidated damages to the Interconnection Customer equal to 1% per day of the actual cost of the initial facilities study or restudy measured from the date the initial study results were confirmed as final until the re-performed study results are provided;
- if a study error is found and if the re-performed study or restudy occurs after the GIA is executed or filed unexecuted with the Commission, and identifies the need for changed, different or additional network upgrades, with increased cost, (i) if the Interconnection Customer continues with the project notwithstanding the increased cost, the Transmission Provider shall pay liquidated damages to the Interconnection Customer equal to 20% of the final, actual cost of changed, different or additional

network upgrades or (ii) if the Interconnection Customer chooses to terminate the project, the Transmission Provider shall pay liquidated damages to the Interconnection Customer equal to 20% of the transmission owner's interconnection facilities and network upgrades identified in the GIA; and

- require the Transmission Provider to pay as liquidated damages 20% of the final, actual cost of any additional or changed network upgrades associated with a contingency that the Transmission Provider failed to include in its final study and list in the GIA.

## V. CONCLUSION

For the foregoing reasons, Petitioner respectfully requests that the Commission initiate a rulemaking to revise certain provisions of its *pro forma* GIP and GIA consistent with the recommendations discussed herein.

Respectfully submitted,

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Document Content(s)

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