BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSISSIPPI

MISSISSIPPI PUBLIC SERVICE COMMISSION **DOCKET NO. 2011-AD-2**

IN RE: ORDER ESTABLISHING DOCKET TO INVESTIGATE THE DEVELOPMENT AND IMPLEMENTATION OF NET METERING PROGRAMS AND STANDARDS

ORDER ADOPTING NET METERING RULE

COMES NOW, the Mississippi Public Service Commission ("Commission") and issues this Final Order concerning the promulgation and implementation of net metering and interconnection standards. For the reasons that follow, the Commission hereby adopts the Mississippi Renewable Energy Net Metering Rule and the Mississippi Distributed Generator Interconnection Rule, attached as respective Exhibits "A" and "B."

I.

In accordance with the procedures of Mississippi Code Annotated § 77-3-45 and the Mississippi Administrative Procedures Act, Miss. Code Ann. §§ 25-43-1.101 *et seq.*, the Commission issued an Order Seeking Comments on Proposed Rules on April 7, 2015. Notice was published according to applicable law and was filed with the Secretary of State in accordance with the Administrative Procedures Act. Numerous parties intervened and/or filed comments, including but not limited to:

1. Entergy Mississippi, Inc.;
2. Mississippi Power Company;
3. The Alliance for Solar Choice;
4. Sierra Club;
5. South Mississippi Electric Power Association;

6. 25x25, Southeast Agriculture and Forestry Energy Resource Alliance and the Vote Solar Initiative;
7. NRG Residential Solar Solutions, Inc.;
8. Gulf States Renewable Energy Industries Association;
9. Electric Power Associations of Mississippi;
10. Mississippi Poultry Association;
11. Mississippi Solar Energy Society, Chapter of the American Solar Energy Society;
12. Mississippi Farm Bureau Federation;
13. John Bailey;
14. David Clark;
15. PosiGen, Inc.; and
16. Sumesh Aurora.

Hundreds of interested, individual ratepayers also submitted comments by email.

Subsequently, on October 6, 2015, the Commission held a public hearing in which the Proposed Rules were discussed and public comments were provided. At the close of the public hearing, the Commission voted to reopen the written comment period for an additional fourteen (14) days. Accordingly, numerous parties submitted supplemental written testimony for the Commission's review. Upon receiving and reviewing all written comments, and after thoughtfully evaluating the testimony presented at the October 6, 2015 public hearing, the Commission prepared the revised Rules attached as Exhibits "A" and "B." As discussed below, the revisions made by the Commission were drawn directly from the comments and testimony submitted in this docket.

II.

Mississippi Code Annotated § 77-3-45 empowers this Commission to "prescribe, issue, amend and rescind such reasonable rules and regulations as may be reasonably necessary or appropriate to carry out the provisions of this chapter."

(Emphasis added). To that end, the Mississippi Legislature declared in Miss. Code Ann. § 77-3-2 that it is "the policy of the State of Mississippi ... to provide fair regulation of public utilities in the interest of the public," "[t]o promote adequate, reliable and economical service to all citizens and residents of the state," [t]o provide just and reasonable rates . . . consistent with long-term management and conservation of energy resources," "[t]o encourage and promote harmony between public utilities, their users and the environment," and "[t]o foster the continued service of public utilities ... consistent with the level of service needed ... for the promotion of the general welfare."[1] Additionally, the Legislature recently granted the Commission broad authority to promote economic development throughout the state.[2] The Net Metering and Interconnection Rules attached as Exhibits "A" and "B" serve these legislative directives, as well as a number of other key policy interests.

To date, forty-four (44) states, the District of Columbia, and numerous U.S. territories have enacted some form of net metering policy permitting individuals to invest in their own distributed energy resources, consume some or all of the energy on-site, and provide excess energy back to the local electric utility grid. Based on its review of the evidence submitted in this Docket, the Commission finds a need for net metering because such a program supports consumers' right to self-supply

[1] Miss. Code Ann. § 77-3-2(1)(a),(f).
[2] Miss. Code Ann. § 77-3-2(1)(i).

electricity as balanced by the need and right to connect to the grid,[3] provides increased consumer choice and introduces innovation into a market dominated by monopolies, has the potential to put downward pressure on rates and provide benefits to all ratepayers,[4] and constitutes a substantial step toward creating a viable solar market in Mississippi. Net metering programs also have the potential to increase economic activity and job growth, and theoretically reduce the cost of compliance with future federal emissions regulations by promoting the use of renewable energy resources. Furthermore, as Synapse Energy Economics, Inc. concluded in its final report, "Distributed solar is expected to avoid costs associated with energy generation costs, future capacity investments, line losses over the transmission and distribution system, future investments in the transmission and distribution system, environmental compliance costs, and costs associated with risk." [5]

III.

Both Statewide and SMEPA contend the Commission does not have jurisdiction to impose net metering rules on their member cooperatives because net metering is ratemaking and federal law otherwise preempts Commission authority. While administering net metering may impose costs, a net metering program is not a rate for the sale of energy *from* a cooperative *to* its member. Therefore, the

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[3] By excluding self-supply from the definition of "public utility" in Miss. Code Ann. § 77-3-3(d), the Public Utility Act impliedly recognizes that consumers have a right to generate electricity for their own use, which coexists with a right to connect to the grid as regulated by the Commission.

[4] Synapse Report at p. 1.

[5] *See* Synapse Report at p. 1. The Synapse Report was publicly filed in this Docket on September 19, 2014.

Commission may exercise jurisdiction over a cooperative relative to net metering. Also, PURPA neither expressly preempts state jurisdiction over net metering and interconnection standards nor necessarily presents a conflict between federal goals and state regulation. Even so, as explained below, the Commission finds that so long as the distribution cooperatives ("EPAs") that take service from the Tennessee Valley Authority ("TVA") continue to participate in a TVA sponsored net metering program, such cooperatives satisfy these Rules. To allow similar treatment among cooperatives, the Commission shall allow the SMEPA cooperatives until October 3, 2016, to file their net metering programs and interconnection standards with this Commission but such programs and standards shall not be inconsistent with the purpose of these Rules. Of course, any SMEPA cooperative may simply utilize these Rules if they so choose.

<u>Exemption from Jurisdiction</u>

While the Commission has broad regulatory authority over the "intrastate business and property" of public utilities, that authority is subject to a notable exception.[6] The Commission may not regulate "the rates for the sales and/or distribution . . . [o]f electricity *by* . . . electric power associations *to* the members thereof *as consumers*.[7]

Statutes such as Miss. Code Ann. § 77-3-5 which "grant [] exemptions from their general operation ... must be strictly construed."[8] Exemptions "must be clear

[6] Miss. Code Ann. § 77-3-5(b).
[7] *Id.* (emphasis added).
[8] *Miss. Dept of Wildlife, Fisheries & Parks v. Miss. Wildlife Enforcement Officers Ass'n, Inc.*, 740 So. 2d 925, 932 (Miss. 1999).

from the language of the statute and cannot be created by construction."[9] In addition, any doubt concerning the applicability of an exemption "must be resolved against the one asserting [it]."[10]

The plain language of Section 77-3-5(b) excludes the Commission from setting rates on only one side of the utility-consumer transaction, that is, sales of electricity *by* the EPA *to* its member as a consumer. Net metering, however, concerns the offsetting of self-generated electricity *by the consumer* and exporting of that self-generated electricity *to the utility*. Net metering thus concerns the opposite transaction from the exemption: accounting for electricity *from* the member *to* the EPA. By its very terms, the exemption of Section 77-3-5(b) does not apply to net metering and interconnection standards.

Section 77-3-5(b) is also inapplicable because net metering does not constitute a *sale of electricity* by an EPA to its members. Net metering accounts for the offsetting or displacement of energy that would otherwise be provided by the public utility. Even when a consumer produces more energy than consumed during a billing period, under the Final Net Metering Rule, the offsetting value of energy credit rolls over month-to-month. As the Federal Energy Regulatory Commission ("FERC") explained about net metering in its *MidAmerican* Opinion:

> The issue in this case is how to measure the transaction between MidAmerican and those entities that have installed generation on their premises.
>
> In essence, MidAmerican is asking this Commission to declare that when, for example, individual homeowners or farmers install small

[9] *Miss. Gaming Comm'n v. Imperial Palace of Miss., Inc.*, 751 So. 2d 1025, 1028 (Miss. 1999).
[10] *Miss. Wildlife Enforcement Officers Ass'n, Inc.*, 740 So. 2d at 932.

> generation facilities to reduce purchases from a utility, a state is preempted from allowing the individual homeowner's or farmer's purchase or sale of power from being measured on a net basis . . . . MidAmerican argues that every flow of power constitutes a sale, and, in particular, that every flow of power from a homeowner or farmer to MidAmerican must be priced consistent with the requirements of either PURPA or the FPA. We find no such requirement.
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> . . . In the case before us we find likewise that no sale occurs when an individual homeowner or farmer (or similar entity such as a business) installs generation and accounts for its dealings with the utility through the practice of netting.[11]

Because no sale of electricity takes place from the member to the EPA, Section 77-3-5(b) is inapplicable.

Preemption of Jurisdiction

The relevant provisions of PURPA, particularly 16 U.S.C. § 2621, do not preempt state law or Commission jurisdiction. To the contrary, these provisions of PURPA are an example of cooperative federalism whereby federal law requires only that states and private entities consider (not adopt) certain federal standards and may choose to implement those particular standards if they desire.[12] Even if the federal minimum standards are adopted, such standards act as a floor that may be augmented by state programs and standards; such federal minimum standards do not serve as unitary federal standards that completely preempt state laws and regulations.[13]

PURPA, itself, makes this clear, requiring that consideration, determination and implementation of the proposed standards be made pursuant to the authority of

[11] *MidAmerican Energy Company*, 94 FERC ¶ 61, 340, pp. 5-6 (2001).
[12] *See FERC v. Mississippi*, 456 U.S. 742, 764-67 (1982).
[13] *Id.* at 767.

and consistent with otherwise applicable state law.[14] PURPA also contains an express acknowledgment and preservation of state authority to adopt net metering and interconnection standards different from those established in PURPA:

> Nothing in this chapter prohibits any State regulatory authority or nonregulated electric utility from adopting, pursuant to State law, any standard or rule affecting electric utilities which is different from any standard established by this subchapter.[15]

PURPA does not prohibit or preempt the Commission from adopting and requiring EPAs to implement net metering and interconnection standards pursuant to Commission authority under state law.

Even so, just because the Commission can do something, it does not follow that the Commission should do something. Applying the Commission's Rules to the TVA EPAs is complex and presents unresolved legal and practical difficulties. For example, the TVA EPAs voluntarily participate in a net metering program offered through TVA. TVA considered the PURPA standards and adopted standards it deemed sufficient and complementary to its relationship with the distribution cooperatives served by TVA. The extent to which the Commission's jurisdiction is distinct from or conflicts with TVA's jurisdiction is not always clear.

Here, TVA does not regulate the relationship between cooperative and member relative to net metering; rather, due to its interpretation of the power contract with the distribution cooperatives, TVA contracts directly with consumers to sell their self-generated power to TVA. The Commission maintains that it regulates the relationship between member/consumer and an EPA, an entity which

[14] 16 U.S.C. § 2621(a), (c).
[15] 16 U.S.C. § 2627(b).

exists by virtue of state law and the certificates granted by the Commission and is regulated by the Commission.

Additionally, the Commission does not read the power contracts to require EPAs to purchase all of their electricity from TVA. A standard TVA wholesale power contract reads, in pertinent part, as follows:

> WHEREAS, Cooperative owns and operates an electric system, and in the operation thereof is presently purchasing and desires to continue to purchase its entire power requirements from TVA[.]

The language above is contained in the recital provisions of the power contract and does not anywhere *require* the cooperative to purchase all of its power from TVA.[16] The language is aspirational and expresses the cooperative's desire to purchase its power from TVA (assuming the power is available at all times) and TVA's inferential willingness to satisfy that desire. An obligation, however, is not created. For example, no substantive provision of the power contract provides, simply, that the cooperative *shall* purchase it entire power requirements from TVA, and TVA *shall* provide all necessary power to the cooperative.

The Commission, however, recognizes two important points. First, TVA does not likely agree with the Commission's assessment, leaving the matter to be resolved by the courts if conflicts arose. Second, the Commission does not desire to unnecessarily disrupt TVA's program; rather, the Commission desires that TVA's

[16] Courts in other jurisdictions have generally recognized that "Recitals in a contract do not control the operative clauses of the contract unless the latter are ambiguous." *Country Community Timberlake Village, L.P. v. HMW Special Utility District of Harris*, 438 S.W.3d 661, 669 (Tex. Ct. App. 2014). Stated differently, "'whereas' clauses are not binding when a contract is otherwise unambiguous. They are merely prefatory recitations of the facts that lead the parties to enter the agreement.'" *Whetstone Candy Co., Inc. v. Kraft Foods, Inc.*, 351 F.3d 1067, 1074 (11th Cir. 2003) (quoting *Johnson v. Johnson*, 725 So. 2d 1209, 1212-1213 (Fla. Dist. Ct. App. 1999) (internal citations omitted).

net metering program succeed. Litigation could be counterproductive, at this time. Therefore, the Commission finds that so long as the TVA EPAs participate in a net metering program offered by TVA, such participation will be deemed to satisfy the purpose and requirements of the Commission's net metering and interconnection standards.

Because the SMEPA EPAs do not contract with TVA for their power, applying the Commission Rules to those EPAs would be less problematic. The Commission, however, recognizes that the EPA model and individual EPA resources are different from an investor-owned utility and that the Final Rules, while appropriate, might not be the best fit in all respects for each SMEPA EPA. In keeping with this Commission's deliberate and incremental approach to net metering, the Commission allows the SMEPA EPAs until October 3, 2016, to develop and file their net metering programs and interconnection standards with this Commission, but such programs and standards shall not be inconsistent with the purpose of these Rules. Of course, any SMEPA EPA may simply utilize these Rules if it so chooses.

IV.

The Final Net Metering Rule attached as Exhibit "A" incorporates the lessons learned from other jurisdictions and provides a flexible framework that will allow this Commission to build upon experience as it is gained in Mississippi. The Commission will proceed deliberately, incorporating changes incrementally, as warranted. As more information becomes available from actual distributed generation adoption, the Commission can, over time, determine whether it may be appropriate to increase compensation to net metering customers, update rate designs, or otherwise modify the rules to encourage customer participation, all while minimizing any adverse consequences for those customers that choose not to install self-generation. With this overarching goal in mind, the Commission has modified the draft Net Metering Rule as follows.

Recommended Framework of Net Metering

The net metering framework contained in the initial draft rule was based on one-channel billing with a carryover of excess energy from month to month for an annualized period. This 1:1 offset effectively would have compensated the generating customer for self-consumed energy at the utility's retail volumetric rate. Any excess energy credits remaining at the end of the annualized period would then have been subject to compensation at the avoided cost rate.

In the written comments and oral testimony submitted in this matter, solar industry representatives and related advocates supported the draft framework, but requested a carryover of energy credits (in kilowatt hours) for an indefinite period. The utilities, on the other hand, cited various concerns about such a methodology and advocated for a 2-channel billing approach, in which Channel 1 (usage) would be billed at the retail rate, and Channel 2 (excess energy) would be valued and credited to customers' accounts each month at an avoided cost rate. The utilities also proposed unlimited carryover of these bill credits.

As Synapse noted in its September 19, 2014 Report in this Docket:

> Distributed generation reduces distribution companies' total energy sales. With lower sales, distribution companies' fixed costs are spread across fewer kilowatt-hours. The effect is a higher price charged for each kilowatt-hour sold ... Net metering customers should be paid for the value of their distributed generation, but non-participants should not bear an undue burden as a consequence of net metering.[17]

The Commission agrees. In order to prevent unfair cost-shifting and allow for accurate valuation of the benefits of excess energy delivered to the grid, the revised Net Metering Rule adopts a 2-channel billing approach with excess energy valued each month and unlimited carryover of bill credits. Included in the comments and materials provided by the Parties is information regarding the history of net metering in other states with a higher penetration of solar, problems that have arisen in those states as a result of net metering policies that include high levels of subsidies, and the recently proposed solutions to those problems. This information reveals that, despite the identification of significant unintended consequences of net metering, state regulators have faced difficulty in reversing course or amending their rules to rectify the unanticipated problems.

Most recently, on October 12, 2015, the Hawaii Public Utilities Commission (PUC) issued an order closing to new customers its existing net metering program.[18] That program, which had been in place in Hawaii for several years, notably allowed the same type of energy credit carryover required under this Commission's April 7 draft Net Metering Rule. In contrast, one of the two replacement programs adopted by the Hawaii PUC in its October 12 Order is the 2-channel billing approach

[17] Synapse report at p. 12.

[18] Hawaii PUC Docket 2014-0192, Decision and Order No. 33258, issued October 12, 2015. Notably, the Hawaii PUC left in place the existing rules for current net metering problem, thereby "grandfathering" them.

adopted by the Commission in the revised Net Metering Rule attached as Exhibit "A." Labeled as the "grid-supply option" to distinguish the program from the existing NEM program, the Hawaii PUC explained, as follows:

> The grid-supply option is intended to provide customers with the option to export excess energy to the grid in exchange for energy credits against the customer's bill, to the extent such energy export provides benefits to the electric system. The grid-supply option is therefore functionally similar to the existing NEM program (see, e.g., HECO's Tariff Rule 18), with the difference that the energy credit rate under the grid-supply option need not be tied to the retail electricity price, but rather can be set at a rate that approximates the relative value of such exported energy to the system.[19]

Although some of the solar advocates have expressed concern that a 2-channel billing arrangement is not true net metering and will not drive additional solar adoption, the recent Hawaii PUC decision neutralizes those claims, stating "the interim options approved herein provide near-term balance, customer choice, and value to both participating and non-participating customers."[20] The Synapse Report also identified options for net metering that are consistent with the 2-channel proposal that values excess energy at the avoided cost each month, and allows that bill credit to roll-over from month-to-month indefinitely.[21]

For these reasons, the Commission supports the adoption of the 2-channel billing approach in which excess energy is valued and credited monthly, with unlimited carryover of bill credits. As discussed in the next section, however, the Commission also finds that benefits in addition to avoided cost should be considered

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[19] *Id.* at pp. 126-127.

[20] *Id.* at p. 168.

[21] *See* Synapse Report at p. 9 ("Examples of ways in which participants are compensated include: .... Receiving a pre-determined rate as a credit on their monthly bill, but with no set guarantee for how long they can roll over....").

in the calculation of the valuation of excess energy each month. Such an approach mitigates the possibility of unfair cost shifting that was raised by the utilities, but properly values the benefits of distributed generation that, while expected to occur, are currently non-quantifiable.

Calculation of Avoided Cost and Other Benefits of Distributed Generation

In both its written comments and oral testimony, EMI proposed the use of an independent, market-based determinant of the costs actually avoided by the excess energy that a net metering customer produces and delivers to the grid. For utilities that are members of a regional transmission organization (RTO), such as EMI, that determinant is the average real-time locational marginal price (LMP) in the utility's load zone. MPC, which is not a member of an RTO, proposed a traditional model-based avoided cost valuation methodology to calculate the appropriate avoided cost rate for its customers. Solar industry representatives and advocates requested compensation at the full retail rate.

The revised Net Metering Rule attached as Exhibit "A" adopts EMI's proposed calculation of avoided cost using MISO LMPs, for utilities in an RTO, plus an adjustment for average line losses but also incorporates a temporary adder of 2.5 cents/kWh for presently non-quantifiable benefits. The adder represents the Commission's thinking that benefits from net metering are probable but recognizes a relative uncertainty regarding the precise value of a particular benefit. For example, residential solar may provide capacity benefits but solar generation is also not dispatchable.

This temporary adder will be replaced within three (3) years with a calculation of Actual Benefits of Distributed generation using Mississippi-specific data based upon an independent consultant study. This independent consultant will work collaboratively with the utilities and other parties to gather information from all stakeholders and provide the Commission with guidance in developing a calculation of benefits that can be demonstrated to have been realized and quantified as a result of the adoption of distributed generation in Mississippi.

This study will allow Mississippi utilities to file, no later than three years from the effective date of these Rules, modified net metering tariffs that reflect a calculation of Actual Benefits of Distributed Generation derived from both independent study and the experience of the utilities. Accordingly, the Non-Quantifiable Expected Benefits adjustment signals the Commission's interest in jump-starting solar adoption in the State of Mississippi, while ensuring that any long-term net metering policies are based on the actual benefits provided by distributed generation.

When combined, these revisions result in a calculation of Total Benefits of Distributed Generation that would be credited to net metering customers of approximately 7.0 to 7.5 cents per kWh for excess energy delivered to the grid. This calculation is consistent with the valuation contained in a recent study conducted by the Tennessee Valley Authority. It also represents a fair compromise between the proposal of EMI, which results in approximately 4.0 to 4.5 cents per kWh, and the proposals of the solar advocates, which argue for compensation no lower than the retail rate (approximately 10 cents per kWh for EMI customers). Furthermore, this framework should reasonably incentivize the adoption of distributed generation while avoiding excessive cost shifting.

Low Income Customers

The written comments and oral testimony in this matter reflect concerns that net metering will result in costs being shifted disproportionately to low income customers, and that those same customers will not have the opportunity to enjoy the benefits of net metering.[22] The Commission finds that these concerns are valid, and therefore orders all utilities subject to these Rules to file, by July 1, 2016, a report on the feasibility of community solar and other options that may broaden solar choice to a wider group of customers in the utilities' services territories. The report should include the feasibility and potential cost-effectiveness of community solar, including options on how such projects and concepts could be implemented.

The revised Net Metering Rule also requires EMI and MPC to offer an additional adder of 2 cents per kWh to the Total Benefits of Distributed Generation calculation for the first 1,000 qualifying low-income customers.[23] To provide sufficient financial certainty to qualifying low-income customers that install net

[22] During the October 6, 2015 public hearing, a representative of the Mississippi Chapter of the American Solar Energy Society testified that only forty percent (40%) of Mississippi homes are currently suitable for rooftop solar. That leaves the majority of Mississippi ratepayers, many of whom are low income families, potentially shouldering increased costs. As EMI pointed out in its Supplemental Post-Hearing Comments, by way of example, Congressional District 2, in which most of EMI's customers are located, has the highest poverty rate in Mississippi at 28.2% (nearly double the national poverty rate). The percentage of renter-occupied housing in that district, moreover, is 37.2% (also above the national average), and rental housing is more likely to be occupied by customers who struggle to pay their utility bill and/or fall below the federal poverty level.

[23] Qualifying customers are those whose household income is at or below 200% of the federal poverty level, or similar requirement proposed by the electric utility to be approved by the Commission.

metered rooftop solar systems, this adder would stay in place for a period of fifteen (15) years from the date the customer begins taking net metering service.

Size Limitation

In keeping with the goal of providing customers the ample opportunities to self-generate if they so choose, the size limit for systems installed on residential properties has been doubled from 10 kW to 20 kW (expressed nameplate DC kilowatts). Further, both the residential and non-residential provisions of the Rules have been clarified to reflect that capacity size limits shall be measured in direct current, and distributed generator facilities (customers' generation) must be located on the customer's physical premises.

Caps

With respect to the net metering cap, many parties raised concerns regarding the manner in which the cap would apply and the percentage at which the cap should be set. The Commission finds that the 3% cap on net metered systems contemplated in the draft Rules should be retained. The Commission is mindful of concerns that have arisen in other states regarding the calculation of net metering caps and, as such, the 3% cap provision has been revised to more clearly show how progress toward the 3% cap is to be calculated each year.

Renewable Energy Credits

During the comment period of this docket, several parties argued that renewable energy credits ("REC's") created by a net metering customer should remain the property of the customer. One utility argued that REC's should be transferred to the electric utility, with the electric utility being responsible for monetizing those REC's in order to spread the benefits among all utility customers.

The Commission generally agrees that any REC's created by a net metering customer should remain with the customer; however, the Commission has added the language, "unless otherwise approved by the Commission" to the final Net Metering Rule due to the inclusion of a Non-quantifiable Expected Benefits Adder in the calculation of avoided cost. The Commission finds that any net metering customers who receive the additional compensation allowed by the adder shall voluntarily transfer REC's to their electric utility as a condition to receiving the Non-quantifiable Expected Benefits adder to the avoided cost.

Third Party Ownership

Both EMI and MPC expressed opposition to the Commission's proposed definition of Renewable Energy Net Metering Interconnection Customer (RENMIC) in the draft Rules, on the basis that third party ownership of solar systems could create uncertainty and legal conflicts related to the status of legally created certificated areas in Mississippi. Solar industry representatives and advocates, on the other hand, argued that third party ownership options are essential to the widespread adoption of distributed generation in Mississippi.

From the Commission's perspective, third party ownership is permissible under the Commission's Net Metering and Interconnection Rules as long as such arrangements comply with state law. Under a typical solar lease arrangement, a net metering customer enters into a service contract with the lessor/owner of a PV solar system and agrees to make monthly lease payments for the use of the equipment over time. This private contractual relationship does not fall within the definition of "public utility" under Miss. Code Ann. § 77-3-3(d) because the electricity ultimately generated is for individual use, rather than "for the public for compensation." Accordingly, the Commission has revised the definition of RENMIC to include the following:

> The electricity customer must own or lease the DGF producing the Renewable Energy on the electricity customer's side of the meter in order to qualify as a RENMIC under this MRENMR, unless otherwise approved by the Commission.

Nevertheless, third party ownership arrangements do give rise to valid consumer protection concerns. Therefore, as discussed in Section V below, the Commission recommends the creation of a working group to address any consumer protection issues that may stem from the third party ownership of net metering equipment.

<u>Notice to Consumers</u>

At the hearing of this matter, some public comments indicated that customers of electric cooperatives may not have information readily available regarding existing net metering and interconnection programs, which has prevented customers from taking full advantage of those options. In order to remedy these concerns, the Commission orders each electric utility to file with the Commission, within three months of the effective date of this Order, the utility's plan to publicize and inform customers of their opportunity to net meter. Potential publication media include the utility's website, bill inserts, social media, or other electronic or paper methods of reaching customers. These consumer education efforts should ensure that interested customers have relevant information as to how to interconnect self-generation equipment, and the manner in which they will be compensated for any excess energy delivered to the grid.

Reopener Provision

Multiple parties submitted comments and testimony recommending the inclusion of a "Reopener Provision" in the Net Metering Rule. Consistent with those recommendations, on the fifth anniversary of the enactment of these Rules, the Commission shall open a new docket to consider the efficacy and fairness of the Net Metering and Interconnection Rules, and shall revise or modify the Rules as necessary.

V.

During the October 6 Public Hearing, Commissioner Renfroe expressed concern for Mississippi contractors, consumers and fire and rescue agencies, as improperly installed solar systems could lead to fires and/or complicate response efforts in the event of a fire. These concerns were echoed by the Mississippi Attorney General's office, which requested the Commission to take steps to ensure both the safe installation of solar systems and the protection of consumers. Various solar industry proponents filed Supplemental Post-hearing Comments asserting that existing federal regulations and building codes are sufficient to ensure consumer protection and the safety of solar systems.

The Commission finds that consumer protection and safety issues should be considered and addressed in conjunction with the appropriate government agencies. Accordingly, the Commission has added a provision to the Net Metering Rule requiring the establishment of a joint working group with representatives of the Commission, the Mississippi Public Utilities Staff, and the Office of the Attorney General to consider consumer protection and safety standards and guidelines for installations of distributed generation systems and education for consumers. The Commission also encourages other interested stakeholders to participate in that working group as identified and requested by the working group.

The working group should assemble on or before March 1, 2016, to begin its task. The Commission urges the working group to, among other things identified at its discretion, 1) track and review consumer complaints related to net metering and interconnection standards; 2) consider and develop, as needed, consumer protection and safety standards and guidelines for installations of distributed generation systems, including the credentialing or certification of installers; 3) education for consumers; and 4) the potential benefits of uniform, statewide permitting for the installation of distributed generation systems. The working group shall make its first report and recommendations to the Commission prior to January 1, 2017.

In addition, the Commission has revised the Final Interconnection Rule to require that utilities inspect and verify that all distributed generation equipment has been appropriately installed, and that all electrical connections have been made in accordance with applicable codes, prior to finalizing an interconnection agreement with a net metering customer. This "witness test" requirement cannot be waived.

VI.

Having considered the law, the comments filed, the testimony presented at the hearing, and the entirety of the record, the Commission finds that the Proposed Rules attached as Exhibits "A" and "B" provide fair regulation within the interest of the public. In addition to supporting Mississippi consumers' right to self-supply electricity, net metering provides potential economic and ecological benefits to both participating and nonparticipating consumers, and to the State of Mississippi as a whole.

IT IS, THEREFORE, ORDERED that the attached Proposed Rules are hereby adopted. The changes are within the scope of the original Notice of Proposed Rule adoption, and therefore, provide fair warning as to the contents. These Rules shall be included in Title 39, Part IV of the next bound publication of the Mississippi Administrative Code and numbered sequentially in accordance with the requirements of the Administrative Procedures Act.

The Executive Secretary is directed to transmit a copy of this Final Order to the Secretary of State's Office in accordance with the Mississippi Administrative Procedures Act, Miss. Code Ann. §§25-43-1.101 *et seq.*

The Executive Secretary is also directed to transmit a copy of this Final Order to all interveners and any other parties of interest identified as well as publish the same according to applicable law.

IT IS FURTHER ORDERED that this Order and the attached Rules shall become effective thirty (30) days after filing with the Secretary of State's Office and shall be deemed issued on the day it is served upon the intervening parties of record by the Executive Secretary of this Commission who shall note the service date in the file of this Docket.

Chairman Lynn Posey voted aye; Vice Chairman Steve Renfroe voted aye, and Commissioner Brandon Presley voted aye.

SO ORDERED, this the 3rd day of December, 2015.

MISSISSIPPI PUBLIC SERVICE COMMISSION

LYNN POSEY, CHAIRMAN

R. STEPHEN RENFROE, VICE-CHAIRMAN

BRANDON PRESLEY, COMMISSIONER

ATTEST: A True Copy

Katherine Collier,
Executive Secretary

Effective this the 3rd day of December, 2015.

MISSISSIPPI PUBLIC SERVICE COMMISSION

Mississippi Renewable Energy Net Metering Rule

The Mississippi Renewable Energy Net Metering Rule (MRENMR) sets forth technical and procedural requirements for Net Metering on qualified Distributed Generator Facilities (DGFs). These DGFs are also subject to the requirements of the Mississippi Distributed Generator Interconnection Rule (MDGIR).

DEFINITIONS

The following capitalized terms, when used in this Rule, shall have the following meanings unless the context clearly indicates otherwise. These definitions are in addition to those found in the MGDIR, which also apply to the MRENMR.

"Billing Period" means the monthly billing period used by an Electric Utility (EU) to measure usage and any excess energy exported by a DGF to the EU, and to bill customers.

"Avoided Cost of Wholesale Power" means the cost to an EU[1] of electric energy that the EU would generate itself or purchase from another source, such as from an organized wholesale power market, but for the purchase from a Renewable Energy Net Metered Interconnection Customer (RENMIC). In essence, the avoided cost is the marginal cost to produce or purchase one more unit of electrical energy. When a RENMIC delivers electricity to an EU, the EU will reduce the equivalent amount of electricity that either is generated at its most expensive operating plant that is not running for reliability purposes or is purchased from an organized wholesale power market. For power generated by an EU, the cost avoided consists of the cost of fuel needed to produce that electricity and the corresponding portion of the plant's operation and maintenance costs and shall include an appropriate average line loss adjustment. No capacity credit is given as part of the calculation of Avoided Cost of Wholesale Power. For an EU that is a member of a regional transmission organization (RTO), the Avoided Cost of Wholesale Power shall be the average real-time locational marginal price (LMP) calculated by the RTO for the EU's load zone(s) Such LMP may be adjusted to reflect the daytime energy production of a solar PV systemand shall include an appropriate average line loss adjustment.

"Non-Quantifiable Expected Benefits" means a temporary adjustment to be included in the Total Benefits of Distributed Generation for benefits of distributed generation that, while expected to occur, are currently non-quantifiable. The Non-Quantifiable Expected Benefits shall be no more than 2.5 cents per kilowatt hour for no longer than three (3) years after the effective date of this rule, which shall serve as a proxy for the Actual Benefits of Distributed Generation further defined below.

"Actual Benefits of Distributed Generation" means actual, quantifiable benefits realized by installed distributed generation over and above the Avoided Cost of Wholesale Power, which shall

[1] An EU is an electric utility within the meaning of Miss. Code Ann. section 77-3-3(d)(i) (Supp 2014).

EXHIBIT

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be calculated based upon information derived from the report of a third party consultant chosen by the Commission (further described below) and the experience of the utilities since implementation of this rule, as well as any additional information that may be available in the industry at that time. The calculation of the Actual Benefits of Distributed Generation shall replace the temporary Non-Quantifiable Expected Benefits no later than three (3) years following the effective date of this rule.

"Low-Income Benefits Adder" means an additional amount to be included in the Total Benefits of Distributed Generation that shall flow to the first 1,000 qualifying customers whose household income is at or below 200% of the federal poverty level (or similar requirement proposed by the EU to be approved by the Commission) who is approved to take service under the EU's net metering tariff. Beginning with the effective date of this rule, the Low-Income Benefits Adder shall be equal to 2 cents per kilowatt hour. To provide sufficient financial certainty to qualifying low income customers that install DGFs, this Low-Income Benefits Adder shall remain in place for a period of fifteen (15) years from the date the customer begins taking net metering service under the EU's net metering tariff.

"Total Benefits of Distributed Generation" means the total amount – expressed in cents per kilowatt hour - that shall be credited to EU customers as a result of excess energy exported by a DGF to the EU, which shall include the Avoided Cost of Wholesale Power plus the Non-Quantifiable Expected Benefits or the Actual Benefits of Distributed Generation, plus, if applicable, the Low-Income Benefits Adder, as further outlined in this rule.

"Exit Fee" means a fee that is paid by a customer that reduces load by using a DGF and is intended to compensate the EU in whole or part for the loss of fixed cost contribution from that customer. Exit fees are not allowed under this Rule, unless otherwise approved by the Commission.

"Renewable Energy Net Metered Interconnection Customer" or "RENMIC" is any electricity customer, such as an industrial, large commercial, residential or small commercial customer, that generates electricity on the customer's side of the meter using a Renewable Energy source. The electricity customer must own or lease the DGF producing the Renewable Energy on the electricity customer's side of the meter in order to qualify as a RENMIC under this MRENMR, unless otherwise approved by the Commission.

"Net Metering" means measuring the real-time kilowatt-hours supplied by the EU to the RENMIC and the kilowatt-hours produced by the RENMIC's DGF and exported to the EU over the applicable Billing Period. Net metering includes the real-time displacement of kilowatt-hours that otherwise would be provided by the EU by kilowatt-hours that were generated by the RENMIC's DGF. An EU may employ a multi-channel meter for separately measuring the RENMIC's electric usage and excess energy exported to the EU.

"Renewable Energy" means electric energy produced from solar technologies, wind energy, geothermal technologies, wave or tidal action, hydro-power facilities, and biomass. Any energy derived from fossil fuels is not considered renewable and does not qualify under the MRENMR.

"Biomass" means a power source that is comprised of combustible solids or gases from forest products, manufacturing waste, or byproducts; products from agricultural and orchard crops; waste or co-products from livestock and poultry operations; waste or byproducts from food processing; urban wood waste; municipal liquid waste treatment operations; and landfill gas.

NET METERING REQUIREMENTS

This MRENMR sets forth the Net Metering requirements that apply to EUs that have customers who self-generate electricity with Renewable Energy on the customer's side of the EU's meter that wish to Net Meter, as indicated by the customer on the Standard Application. These customers are referred to as RENMICs in this Rule.

All EUs shall offer Net Metering to any customer that seeks to generate electricity on the customer's side of the EU's meter using Renewable Energy sources, provided:

(1) For residential customers, Net Metering nameplate direct current capacity of the aggregated DGFs at the customer's premises shall be limited to 20 kW and shall meet the requirements of the MDGIR;

(2) For non-residential customers, Net Metering nameplate direct current capacity for the aggregate DGFs at the customer's premises shall be limited to 2 MW and shall meet the requirements of the MDGIR.

EUs may refuse additional net metering requests if the total Net Metering direct current capacity in kW, as reported through these requirements, exceeds at any time 3 percent of the EU's total system peak demand expressed in kW recorded during the prior calendar year.

Each EU shall develop a tariff for Net Metering and interconnection policies in concordance with this MRENMR and the MDGIR. Each EU shall make Net Metering available to eligible RENMICs on a first-come, first-served basis until such time as the aforementioned cap has been reached.

An EU shall provide Net Metering at non-discriminatory rates that are identical, with respect to rate structure and level, retail rate components, and any monthly fixed charges, to the rates that a RENMIC would be charged if not a RENMIC, unless otherwise approved by the Commission.

In each Billing Period, energy supplied to the RENMIC from the EU as recorded on the EU's bi-directional net meter will be billed using appropriate commission-approved rate and rider schedules. This provision means that energy self-supplied by the RENMIC, up to the amount supplied from the EU to the RENMIC (e.g., through the recording of meter Channel 1) will be credited to the RENMIC at the full retail rate (i.e., effectively displacing energy supplied from the EU). During that same Billing Period, any excess energy supplied from the RENMIC to the EU and recorded on the EU's bi-directional net meter in kWh (e.g., through meter Channel 2) will be credited on the RENMIC's bill at the applicable Total Benefits of Distributed Generation expressed in cents per kWh and shall be accounted for through the EU's fuel adjustment clause. The customer's monthly bill will be the total of billing for any usage (i.e., as recorded on meter Channel 1) subject to any customer charge and/or minimum bill provisions in the EU's rate and rider schedules less any credit due to the customer from excess energy exported to the EU (i.e., as recorded on meter Channel 2). If the sum total of the monthly bill is negative, any such amount will be carried over to the next Billing Period and applied to any charges arising during the subsequent Billing Period.

Beginning with the effective date of this rule, Total Benefits of Distributed Generation shall temporarily be equal to the Avoided Cost of Wholesale Power plus Non-Quantifiable Expected Benefits. Further, Non-Quantifiable Expected Benefits shall be equal to 2.5 cents/kWh, which may be modified downward at any time by order of this Commission, should the Commission find it is in the public interest to do so. Within sixty (60) days of the effective date of this rule, each EU shall file with the Commission net metering tariffs consistent with the provisions of this rule for consideration and approval by the Commission.

In the calculation of Total Benefits of Distributed Generation, Non-Quantifiable Expected Benefits shall be replaced and subsumed by Actual Benefits of Distributed Generation no later than three (3) years following the effective date of this rule. In order to develop a calculation for Actual Benefits of Distributed Generation within that three-year timeframe, the Commission shall cause a study to be performed by an independent consultant beginning no earlier than one year after the effective date of this rule, the costs of which shall be paid by each EU whose rates are regulated by the Commission under the Mississippi Public Utilities Act, §§ 73-3-1 *et seq.*, and recovered through each such EU's net metering tariff. Said independent consultant will work collaboratively with the utilities and gather information from other stakeholders to provide the Commission with guidance in developing a calculation of benefits that can be demonstrated to have been realized and quantified as a result of the adoption of distributed generation in Mississippi. No later than three (3) years from the effective date of this rule, the Commission shall instruct each EU to file modifications to their net metering tariffs to reflect a calculation of Actual Benefits of Distributed Generation consistent with conclusions of the study and data provided by the EUs.

Each new Billing Period shall begin with zero kWh credits to the RENMIC; however, subject to the provisions above, the customer may carry over any value of energy credit arising from the prior Billing Period(s). When a customer closes his or her account with the EU, if the RENMIC has accumulated a dollar balance as a result of excess energy delivered to the EU, any such balance, net of costs owed to the EU, shall be paid to the RENMIC.

Credit for any excess energy exported to the EU shall not be applied to reduce any fixed monthly customer charges or minimum bill provisions imposed by the EU under Commission-approved rate and rider schedules.

An EU shall offer a RENMIC the choice of a time differentiated energy tariff rate or a non-time-differentiated energy tariff rate, if the EU offers the choice to customers in the same rate class as the RENMIC. If a RENMIC uses a retail billing arrangement that has time- differentiated rates, the EU shall net any production from the DGFs against the customer's consumption within the same time-of-use period in the Billing Period and any excess energy exported to the EU will be credited as described above.

Any renewable energy credits (RECs) created by the RENMIC are the property of the RENMIC, unless otherwise approved by the Commission. The EU shall not charge any back-up, standby, or Exit Fees to a RENMIC, unless otherwise approved by the Commission.
An EU shall not charge a RENMIC any fee or charge, or require additional equipment, insurance or any other requirement, unless the fee, charge, or other requirement is specifically authorized in this MRENMR or the MDGIR, or the fee would apply to other customers in the same rate class that are not RENMICs, or unless otherwise approved by the Commission.

All RENMICs must be electrically interconnected with their EU pursuant to the provisions of the MDGIR. All rules and regulations for interconnected DGFs within the MDGIR apply to RENMICs. Any Distribution System Upgrades, including additional equipment needed that is associated with the export of electricity, shall be at the RENMIC's expense, per the MDGIR.

As a further requirement under this rule, each EU shall file with the Commission within three months of the effective date of this rule the EU's plan to publicize and inform its customers, whether through a website, a bill insert, or other form of communication, of the opportunities available to interconnect DGFs and receive compensation for excess energy delivered to the grid.

Nothing in this document shall abrogate any person's obligation to comply with all applicable Federal or State laws, rules or regulations, including the MDGIR.

METERS AND METERING

A RENMIC shall be equipped with metering equipment that can measure the flow of electricity in each direction at the same time. This is typically accomplished through use of a single bi-directional meter that records customer usage as well as excess energy exported to the EU (e.g., energy supplied to the customer net of the output of the RENMIC is measured on Channel 1 and excess energy supplied by the RENMIC to the EU in excess of the customer's requirements is measured on Channel 2).

An EU may choose to use an existing electric revenue meter if the following criteria are met:

(1) The meter is capable of measuring the flow of electricity both into and out of the RENMIC at the same time; and

(2) The meter is accurate to within plus or minus five percent when measuring excess energy flowing from the RENMIC to the EU.

If the RENMIC's existing electric revenue meter does not meet the requirements above, the EU shall install a new revenue meter for the RENMIC, at the RENMIC's expense, within 10 business days after the interconnection agreement is executed and approved. If the EU offers a time-differentiated rate chosen by the RENMIC, the meter shall have the capability to appropriately record energy flows in each direction during any time-differentiated period.

Any subsequent revenue meter change will be at the EU's expense, meaning such meter expense will not be charged to an individual RENMIC but shall become part of the EU's overall cost of service and subsequent revenue requirement.

REPORTING REQUIREMENTS

Each EU with one or more RENMICs connected to its grid shall submit to the Mississippi Public Service Commission a Net Metering report within 90 days of the end of each calendar year. The report shall include the following information regarding RENMICs during the reporting period:

(1) The total energy expressed in kilowatt-hours supplied to the EU's grid by RENMICs and a description of any estimation methodology used;

(2) The total number of RENMICs that were paid for excess energy exported to the EU at the end of any Billing Period(s) during the prior calendar year;

(3) The total dollar amount by month that the EU paid to RENMICs for excess energy exported to the EU during the prior calendar year;

(4) The total number of net metering DGFs by resource type that were interconnected at the end of the prior calendar year;

(5) The total rated nameplate direct current generating capacity of net metering DGFs installed during the prior calendar year broken out by resource type; and

(6) The percentage of the EU's total system peak demand from the prior calendar year represented by the total rated nameplate direct current generating capacity of

net metering DGFs.

For purposes of these reporting requirements, any estimates shall be made using Commission-approved protocols unless no such protocols are available, in which case the estimates shall be accompanied by detailed calculations demonstrating how the estimates were made.

SAFETY AND CONSUMER PROTECTION WORKING GROUP

In order to ensure adequate safeguards for safety and consumer protection, a joint working group shall be established between representatives of the Commission, the Mississippi Public Utilities Staff, the Office of the Mississippi Attorney General, and qualified stakeholders, as identified and requested by the working group. Prior to January 1, 2017, the working group shall establish and present to the Commission an initial set of consumer protection and safety standards and guidelines related to the installation and use of distributed generation systems. Thereafter, the working group shall reconvene as necessary to discuss additional issues related to net metering as they arise, and to present any recommendations on such issues to the Commission.

REOPENER

Five years from the effective date of this Rule, the Commission shall open a new docket to assess the efficacy and functionality of the MRENMR, and make any subsequent revisions or modifications of the Rule that may be deemed necessary at that time.

Mississippi Distributed Generator Interconnection and Net Metering

Subpart I: Mississippi Distributed Generator Interconnection Rule

Chapter 01: Introduction

The Mississippi Distributed Generation Interconnection Rule (MDGIR) sets forth standards to establish the technical and procedural requirements for Distributed Generator Facilities (DGFs) to be interconnected and operated in Parallel with the Electric Distribution System (EDS) owned or operated by Electric Utilities (EUs) in Mississippi under the jurisdiction of the Mississippi Public Service Commission (Commission). Capitalized terms used in this rule have the meaning specified in the section titled DEFINITIONS.

Chapter 02: Definitions

When used in this chapter, the following terms and phrases shall have the following meaning:

100 **"Adverse System Impact"** means a negative effect, due to technical or operational limits on conductors or equipment being exceeded, that compromises the safety and reliability of the EDS.

101 **"Applicable Laws and Regulations"** means all duly promulgated and applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

102 **"Certificate of Completion"** means a certificate in a completed form approved by the Commission containing information about the Interconnection Equipment to be used, its installation and local inspections.

103 **"Certified Interconnection Equipment" or "Certified Equipment"** or **"Certified"** means a designation that the Interconnection Equipment meets the following requirements:

1. The Interconnection Equipment has been tested by a Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration (OSHA) in accordance with the following relevant codes and standards:

    a. IEEE 1547.1 Standard for Conformance Tests Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems; and

    b. Underwriters Laboratories ("UL"), UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems;

2. The Interconnection Equipment shall meet the requirements of the most current approved version of each code and standard listed above, as amended and supplemented at the time the Interconnection Request is submitted to be deemed Certified;

3. The Interconnection Equipment has been labeled and is publicly listed by such NRTL at the time of the interconnection application;

4. The Interconnection Customer verifies that the intended use of the Interconnection Equipment falls within the use or uses for which the Interconnection Equipment is labeled and is listed by the NRTL;

5. If the Interconnection Equipment is an integrated equipment package such as an inverter, then the Interconnection Customer shall show that the generator or other electric source being utilized is compatible with the Interconnection Equipment and is consistent with the testing and listing specified for this type of Interconnection Equipment;

6. If the Interconnection Equipment includes only interface components (switchgear, multi-function relays, or other interface devices), an Interconnection Customer shall demonstrate that the generator or other electric source being utilized is compatible with the Interconnection Equipment and is consistent with the testing and listing specified for this type of Interconnection Equipment; and

7. Certified Interconnection Equipment shall not require further design testing or Production Testing, as specified by IEEE Standard 1547 Sections 5.1 and 5.2, or additional Interconnection Equipment modification to meet the requirements. However, nothing herein shall preclude the need for an on-site Witness Test or operational test by the Interconnection Customer.

104 **"Commission"** means the Mississippi Public Service Commission.

105 **"Commissioning Tests"** means the tests applied to a DGF by an Interconnection Customer after construction is completed to verify that the DGF does not create Adverse System Impacts. At a minimum, the scope of the Commissioning Tests performed shall include the commissioning test specified by IEEE Standard 1547 section 5.4 "Commissioning Tests."

106 **"Distributed Generator Facility"** or **"DGF"** means the equipment used by an Interconnection Customer to generate or store electricity that operates in Parallel with the EDS. A DGF typically includes an electric generator, prime mover, and the Interconnection Equipment required to safely interconnect with the EDS or local electric power system.

107 **"Distribution System Upgrade"** means a required addition or modification to the EU's EDS at or beyond the Point of Common Coupling (PCC) to accommodate the

interconnection of a DGF. Distribution System Upgrades do not include Interconnection Facilities.

108 **"Electric Utility" or "EU"** means an electric public utility that distributes electricity to customers and is subject to the jurisdiction of the Commission pursuant to the provisions of Mississippi Code Annotated §§ 77-3-1, *et seq*.

109 **"Electric Distribution System" or "EDS"** means the facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries from interchanges with higher voltage transmission networks that transport bulk power over longer distances. The voltage levels at which EDSs operate differ among areas but generally carry less than 69 kilovolts of electricity. EDS has the same meaning as the term Area EPS, as defined in 3.1.6.1 of IEEE Standard 1547.

110 **"Facilities Study"** means an engineering study conducted by the EU to determine the required modifications to the EU's EDS, including the cost and the time required to build and install such modifications as necessary to accommodate an Interconnection Request.

111 **"Fault Current"** means the electrical current that flows through a circuit during an electrical fault condition. A fault condition occurs when one or more electrical conductors contact ground or each other. Types of faults include phase to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase.

112 **"Feasibility Study"** means a study performed to identify the existence of obvious adverse impacts before additional studies are undertaken for the proposed project to continue in the process.

100 **"Governmental Authority"** mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, EU or any affiliate thereof.

101 **"IEEE Standard 1547"** means the Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 1547 (2003) "Standard for Interconnecting Distributed Resources with Electric Power Systems," as amended and supplemented at the time the Interconnection Request is submitted.

102 **"IEEE Standard 1547.1"** means the IEEE Standard 1547.1 (2005) "Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems," as amended and supplemented at the time the Interconnection Request is submitted.

103 **"Interconnection Agreement" or "Agreement"** means a form of interconnection agreement approved by the Commission which is applicable to Interconnection Requests pertaining to DGFs. The agreement between the Interconnection Customer and the EU governs the connection of the DGF to the EU's EDS, as well as the ongoing operation of the DGF after it is connected to the EU's EDS.

104 **"Interconnection Application" or "Application"** means a form of interconnection application approved by the Commission which is applicable to Interconnection Requests pertaining to DGFs. This application provides the information needed by the EU to review the request for interconnection. For the Level 1 review process, the Application and Agreement are part of the same document.

105 **"Interconnection Customer"** means an entity that submits an Interconnection Request for a DGF to an EU's EDS.

106 **"Interconnection Equipment"** means a group of equipment, components, or an integrated system connecting an electric generator with a local electric power system or an EDS that includes all interface equipment including switchgear, protective devices, inverters or other interface devices. Interconnection equipment may be installed as part of an integrated equipment package that includes a generator or other electric source.

107 **"Interconnection Facilities"** means facilities and equipment required by the EU to accommodate the interconnection of a DGF. Collectively, Interconnection Facilities include all facilities and equipment between the DGF and the PCC, including modification, additions, or upgrades that are necessary to physically and electrically interconnect the DGF to the EDS. Interconnection facilities are sole use facilities and do not include Distribution System Upgrades.

108 **"Interconnection Request"** means an Interconnection Customer's request, in the form of an Application approved by the Commission, requesting the interconnection of a new DGF, or to increase the capacity or modify operating characteristics of an existing approved DGF that is interconnected with the EU's EDS.

109 **"Line Section"** means that portion of an EU's distribution system connected to an Interconnection Customer, bounded by automatic sectionalizing devices or the end of the distribution line.

110 **"Local Electric Power System" or "Local EPS"** means facilities that deliver electric power to a load that are contained entirely within a single premises or group of premises. Local electric power system has the same meaning as the term local electric power system defined in 3.1.6.2 of IEEE Standard 1547.

111 **"Minor Equipment Modification"** means changes to the DGF that do not have a material impact on safety or reliability of the EDS.

112 **"Mississippi Distributed Generation Interconnection Rule (MDGIR)"** means the most current version of the procedures for interconnecting Distributed Generator Facilities adopted by the Mississippi Public Service Commission.

113 **"Nameplate Capacity"** means the maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer and is usually indicated on a nameplate physically attached to the power production equipment.

114 **"Nationally Recognized Testing Laboratory" or "NRTL"** means a qualified private organization that meets the requirements of the Occupational Safety and Health Administration's (OSHA) regulations. NRTLs perform independent safety testing and product certification. Each NRTL shall meet the requirements as set forth by OSHA in the NRTL program.

115 **"Parallel Operation" or "Parallel"** means the sustained state of operation over 100 milliseconds, which occurs when a DGF is connected electrically to the EDS and thus has the ability for electricity to flow from the DGF to the EDS.

116 **"Point of Common Coupling" or "PCC"** means the point where the DGF is electrically connected to the EDS. Point of common coupling has the same meaning as defined in 3.1.13 of IEEE Standard 1547.

117 **"Primary Line"** means a distribution line rated at greater than 600 volts.

118 **"Production Test"** means production test as defined in IEEE Standard 1547.

119 **"Queue Position"** means the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the EU.

120 **"Radial Distribution Circuit"** means a circuit configuration where independent feeders branch out radially from a common source of supply. From the standpoint of a utility system, the area described is between the generating source or intervening substations and the customer's entrance equipment. A radial distribution system is the most common type of connection between a utility and load in which power flows in one direction from the utility to the load.

121 **"Scoping Meeting"** means a meeting between representatives of the Interconnection Customer and EU conducted for the purpose of discussing alternative interconnection options, exchanging information including any EDS data and earlier study evaluations that would be reasonably expected to impact interconnection options, analyzing information, and determining the potential feasible points of interconnection.

122 **"Secondary Line"** means a service line subsequent to the Primary Line that is rated for 600 volts or less, also referred to as the customer's service line.

123 **"System Impact Study"** means a study that identifies the electric system impacts that would result if the proposed DGF were interconnected without DGF modifications or EDS modifications, focusing on the Adverse System Impacts identified in the Feasibility Study.

124 **"UL Standard 1741"** means Underwriters Laboratories' standard titled "Inverters Converters, and Controllers for Use in Independent Power Systems," as amended and supplemented at the time the Interconnection Request is submitted.

125 **"Witness Test"** means verification (through on-site observation) by the EU that the installation evaluation required by IEEE Standard 1547 Section 5.3 and the Commissioning Test required by IEEE Standard 1547 Section 5.4, have been adequately performed. For Interconnection Equipment that has not been Certified, the Witness Test shall also include the verification by the EU of the on-site design tests as required by IEEE Standard 1547 Section 5.1 and verification by the EU of Production Tests required by IEEE Standard 1547 Section 5.2. All tests verified by the EU are to be performed in accordance with the applicable test procedures specified by IEEE Standard 1547.1.

Chapter 03: INTERCONNECTION REQUESTS, FEES, AND FORMS

100 Interconnection Customers seeking to interconnect a DGF shall submit an Interconnection Request to the EU that owns the EDS to which interconnection is sought, using an application approved by the Commission. Electronic versions of such Commission-proved Application forms shall be posted on the EU's website. The EU shall establish processes for accepting Interconnection Requests electronically.

101 When an Interconnection Customer is not currently a customer of the EU at the proposed PCC, upon request from the EU, the Interconnection Customer shall provide proof of site control evidenced by a property tax bill, deed, lease agreement, or other legally binding contract.

102 Interconnection fees shall be governed as follows for all Interconnection Requests and shall be published on each EU's website:

1. An EU may not charge an application, or other fee, to an applicant that requests Level 1 interconnection review. However, if an application for Level 1 interconnection review is denied because it does not meet the requirements for Level 1 interconnection review and the applicant resubmits the application under another review procedure in accordance with the MDGIR, the EU may impose a fee for the resubmitted application, consistent with this section.
2. For a Level 2 interconnection review, the EU may charge fees of up to $50.00 plus $1.00 per kilowatt of the customer-generator facility's capacity, plus the reasonable cost of any required minor modifications to the electric distribution

system or additional review. Costs for such minor modifications or additional review will be based on the EU's non-binding, good faith estimates and the ultimate actual installed costs. Costs for engineering work done as part of any additional review will not exceed $100.00 per hour.

3. For a Level 3 interconnection review, the EU may charge fees of up to $100.00 plus $2.00 per kilowatt of the customer-generator facility's capacity, as well as charges for actual time spent on any required impact or facilities studies. Costs for engineering work done as part of an impact study or interconnection facilities study will not exceed $100.00 per hour. If the EU must install facilities in order to accommodate the interconnection of the customer generating facility, the cost of such facilities will be the responsibility of the applicant.

103 When the EU determines that an Interconnection Request is complete, a modification of DGF design by the Interconnection Customer other than a Minor Equipment Modification that is not agreed to in writing by the EU shall require submission of a new Interconnection Request.

Chapter 04: INTERCONNECTION REVIEW LEVELS

100 The EU shall review Interconnection Requests using one of the three levels of review procedures established below. The EU shall first use the level of DGF Agreement specified by the Interconnection Customer in the Application. The EU may not impose additional requirements not specifically authorized unless the EU and the Interconnection Customer mutually agree to do so in writing.

101 When an Interconnection Request is for an increase in capacity for an existing DGF, the Interconnection Request shall be evaluated on the basis of the new total Nameplate Capacity of the DGF.

102 When an Interconnection Request is for a DGF that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single PCC, the Interconnection Request shall be evaluated on the basis of the aggregate Nameplate Capacity of the multiple devices.

Chapter 05: LEVEL 1 INTERCONNECTION REVIEWS

100 The EU shall use Level 1 review procedures to evaluate Interconnection Requests when:

1. The DGF is inverter-based;
2. The DGF has a Nameplate Capacity of 20 kW or less; and
3. The Interconnection Equipment proposed for the DGF is Certified.

101 For Level 1 Interconnection Review, the EU shall first evaluate the potential for Adverse System Impacts using the following screens, which must be satisfied:

1. For interconnection of a proposed DGF to a Line Section on a Radial Distribution Circuit, the aggregated generation on the Line Section, including the proposed DGF, shall not exceed 15% of the Line Section annual peak load.

2. When a proposed DGF is to be interconnected to a single-phase shared Secondary Line, the aggregate generation capacity on the shared Secondary Line, including the proposed DGF, may not exceed 20 kW.

3. When a proposed DGF is single-phase and is to be interconnected to a center tap neutral of a 240 volt service, its addition may not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

4. Construction of facilities by the EU on its own system is not required to accommodate the DGF.

102 The Level 1 Interconnection Review shall then be conducted in accordance with the following procedures:

1. An EU shall, within 10 business days after receipt of the Interconnection Request, inform the Interconnection Customer in writing or by electronic mail that the Interconnection Request is complete or incomplete and indicate what, if any, materials are missing.

2. When an Interconnection Request is complete, the EU shall assign a Queue Position.

3. The EU shall, within 15 business days after notifying a Level 1 applicant that the application is complete, indicate that the DGF equipment meets all Level 1 criteria, verify the DG can be interconnected safely and reliably using Level 1 screens, and provide a conditionally approved Level 1 Interconnection Application Form and Agreement to the Interconnection Customer.

103 Unless the EU determines and demonstrates to the Interconnection Customer that a DGF cannot be interconnected safely or reliably to its system and provides a letter to the Interconnection Customer explaining its reasons for denying an Interconnection Request, the EU's final approval of the Interconnection Agreement is subject to the following conditions:

1. 'The DGF has been approved by local or municipal electric code officials with jurisdiction over the interconnection;

2. The EU has received the required information on the Certificate of Completion from the Interconnection Customer. Completion of local inspections may be designated on inspection forms used by local inspecting authorities; and

3. The EU has completed its Witness Test in accordance with the MDGIR.

104 Within 10 business days of the estimated commissioning date indicated on the Interconnection Request, the EU shall, upon reasonable notice and at a mutually convenient time, conduct a Witness Test of the DGF to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes.

105 When a DGF is not approved under a Level 1 review, the Interconnection Customer may submit a new Interconnection Request for consideration under Level 2 or Level 3 procedures.

Chapter 06: LEVEL 2 INTERCONNECTION REVIEWS

100 The EU shall use the Level 2 Interconnection Review procedure to evaluate an Interconnection Request when:

1. The DGF has a Nameplate Capacity rating of 2 MW or less;

2. The Interconnection Equipment proposed for the DGF is Certified; and

3. The aggregated total of the Nameplate Capacity of all of the generators on the circuit, including the proposed DGF, is 2 MW or less.

101 No construction of facilities by an EU shall be required to accommodate the DGF, except as permitted by an additional review for minimal modifications of the EDS, as described in these Level 2 procedures.

102 For Level 2 Interconnection Review, the EU first shall evaluate the potential for Adverse System Impacts using the following screens, which must be satisfied:

1. For interconnection of a proposed DGF to a radial distribution circuit, the aggregated generation on the Line Section, including the proposed DGF, may not exceed 15% of the Line Section annual peak load.

2. The proposed DGF, in aggregation with other generation on the distribution circuit, may not contribute more than 10% to the distribution circuit's maximum Fault Current at the point on the Primary Line nearest the Point of Common Coupling (PCC).

3. The proposed DGF, in aggregate with other generation on the distribution circuit, may not cause any distribution protective devices and equipment (including

substation breakers, fuse cutouts, and line reclosers), or other customer equipment on the EDS to be exposed to Fault Currents exceeding 87.5% of the short circuit interrupting capability. The Interconnection Request may not receive approval for interconnection on a circuit that already exceeds 87.5% of the short circuit interrupting capability.

4. When a DGF is to be connected to three-phase, three-wire primary EU distribution lines, a three-phase or single-phase generator shall be connected phase-to-phase.

5. When a DGF is to be connected to three-phase, four-wire primary EU distribution lines, a three-phase or single-phase generator shall be connected line-to-neutral and shall be effectively grounded.

6. When the proposed DGF is to be interconnected on a single-phase shared Secondary Line, the aggregate generation capacity on the shared Secondary Line, including the proposed DGF, shall not exceed 20 kW.

7. When a proposed DGF is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition may not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

8. A DGF, in aggregate with other generation interconnected to the distribution side of a substation transformer feeding the circuit where the DGF proposes to interconnect, may not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity.

9. No construction of facilities by an EU on its own system shall be required to accommodate the DGF.

103 The Level 2 Interconnection Review shall then be conducted in accordance with the following procedures:

1. An EU shall, within 10 business days after receipt of the Interconnection Request, inform the Interconnection Customer in writing or by electronic mail that the Interconnection Request is complete or incomplete and indicate what, if any, materials are missing. As part of this process, the EU shall assign a Queue Position. The Queue Position of the Interconnection Request shall be used to determine the potential Adverse System Impact of the DGF based on the relevant screening criteria. If there are higher queued Interconnection Requests on the same radial line circuit, the EU shall evaluate the Interconnection Requests by performing any Level 2 screens requiring aggregate capacity calculations and determine if the DGF in combination with the higher queued Interconnection Requests exceeds any of the aggregate capacity requirements. If an aggregate

capacity requirement is exceeded, the EU shall notify the Interconnection Customer and shall not be obligated to meet the timeline for reviewing the Interconnection Request until such time as the EU has completed the review of all other Interconnection Requests that have a higher Queue Position and impact the aggregate capacity calculation that has been exceeded.

2. At the time an EU determines additional information is required to complete an evaluation, the EU shall request the information. The time necessary to complete the evaluation may be extended by mutual agreement of the parties, but only to the extent of the time required for receipt of the additional information. During an extension of time to submit additional information, the EU may not alter the Interconnection Customer's Queue Position.

3. Within 20 business days after the EU notifies the Interconnection Customer that it has received a completed Interconnection Request, the EU shall:

    a. Evaluate the Interconnection Request using the Level 2 screening criteria;

    b. Review any analysis provided by the Interconnection Customer, using the same criteria used by the customer; and

    c. Provide the Interconnection Customer with the EU's evaluation, including a comparison of the results of its own analyses with those of Interconnection Customer, if applicable. When an EU does not have a record of receipt of the Interconnection Request and the Interconnection Customer can demonstrate that the original Interconnection Request was delivered, the EU shall expedite its review to complete the evaluation of the Interconnection Request within 20 business days of the Interconnection Customer's re-submittal.

104 The EU shall provide the Interconnection Customer a DGF Interconnection Agreement within 5 business days of its determination that the Interconnection Request passes the Level 2 screening criteria.

105 When a DGF has failed to meet one or more of the Level 2 screens, the EU shall offer to perform additional review for minimal modifications of the EDS to determine whether minimal modifications to the EDS would enable the interconnection to be made consistent with safety, reliability and power quality criteria. The EU shall provide the Interconnection Customer with a nonbinding, good faith estimate of the costs of additional review for minimal modifications of the EDS. The EU shall undertake the additional review for minimal modifications of the EDS or the modifications only after the Interconnection Customer consents to pay for the review and modifications.

106 If the DGF fails one or more of the Level 2 screening criteria but the EU determines that minimal modifications to the EDS would enable the DGF to interconnect safely and reliably, the EU shall provide the Interconnection Customer a DGF Interconnection Agreement within 5 business days of making that determination.

107 If the EU finds that the DGF cannot be interconnected with minimal modifications to the EDS, the EU shall provide the Interconnection Customer a letter explaining its reasons for denying the Interconnection Request. The Interconnection Customer may submit a new Interconnection Request for consideration under a Level 3 interconnection review.

108 An Interconnection Customer shall have 30 business days to sign and return the Agreement. When an Interconnection Customer does not sign the DGF Interconnection Agreement within 30 business days, the Interconnection Request shall be deemed withdrawn unless the Interconnection Customer requests in writing prior to the expiration of the 30 business day period to extend the deadline. The EU may not unreasonably deny the request for extension.

109 The DGF Interconnection Agreement shall not become final until:

1. The milestones agreed to in the DGF Interconnection Agreement are satisfied;
2. The DGF is approved by electric code officials with jurisdiction over the interconnection;
3. The Interconnection Customer provides a Certificate of Completion to the EU. Completion of local inspections may be designated on inspection forms used by local inspecting authorities; and
4. The Witness Test was successfully completed per the terms and conditions found in the Agreement.

110 If the DGF is not approved under a Level 2 review, the EU shall provide the Interconnection Customer a letter explaining its reasons for denying the Interconnection Request. The Interconnection Customer may submit a new Interconnection Request for consideration under a Level 3 interconnection review. The Queue Position assigned to the Level 2 Interconnection Request shall be retained provided the request is made within 15 business days of notification that the current Interconnection Request is denied.

Chapter 07: LEVEL 3 INTERCONNECTION REVIEWS

100 The EU shall use the Level 3 review procedure to evaluate an Interconnection Request when the Interconnection Customer requests Level 3 review.

101 The Level 3 review shall be conducted in accordance with the following process:

1. An EU shall, within 10 business days of receipt of an Interconnection Request, inform the Interconnection Customer in writing or by electronic means that the Interconnection Request is complete or incomplete and indicate what, if any, materials are missing.

2. When the Interconnection Request is deemed not complete, the EU shall provide the Interconnection Customer with a written list detailing information required to complete the Interconnection Request. The Interconnection Customer shall have 10 business days to provide appropriate data in order to complete the Interconnection Request, or the Interconnection Request shall be considered withdrawn. The parties may agree to extend the time for receipt of the additional information. The Interconnection Request shall be deemed complete when the required information has been provided by the Interconnection Customer, or the parties have agreed that the Interconnection Customer may provide additional information at a later time.

3. When an Interconnection Request is complete, the EU shall assign a Queue Position. The Queue Position of an Interconnection Request shall be used to determine the cost responsibility necessary for the facilities to accommodate the interconnection. The EU shall notify the Interconnection Customer about other higher-queued Interconnection Customers that have the potential to impact the cost responsibility.

4. Level 3 Scoping Meetings shall be conducted as follows:

    a. By mutual agreement of the parties, the Scoping Meeting, interconnection Feasibility Study, interconnection System Impact Study, or interconnection Facilities Study provided for in a Level 3 review may be waived;

    b. If agreed to by the parties, a Scoping Meeting shall be held within 10 business days, or other mutually agreed to time, after the EU has notified the Interconnection Customer that the Interconnection Request is deemed complete, The purpose of the meeting shall be to review the Interconnection Request, existing studies relevant to the Interconnection Request, and the results of the Level 1 or Level 2 screening criteria;

    c. When the parties agree at a Scoping Meeting that an interconnection Feasibility Study shall be performed, the EU shall provide to the Interconnection Customer, no later than 5 business days after the Scoping Meeting, an interconnection Feasibility Study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study;

    d. When the parties agree at a Scoping Meeting that an interconnection Feasibility Study is not required, the EU shall provide to the

Interconnection Customer, no later than 5 business days after the Scoping Meeting, an interconnection System Impact Study agreement, including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study; and

e. When the parties agree at the Scoping Meeting that an interconnection Feasibility Study and System Impact Study are not required, the EU shall provide to the Interconnection Customer, no later than 5 business days after the Scoping Meeting, an interconnection Facilities Study agreement including an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study.

5. Any required interconnection studies shall be carried out using the following guidelines:

   a. An interconnection Feasibility Study shall include the following analyses and conditions for the purpose of identifying and addressing potential Adverse System Impacts to the EU's EDS that would result from the interconnection:

   b. Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

   c. Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

   d. Initial review of grounding requirements and system protection;

   e. Description and nonbinding estimated cost of facilities required to interconnect the DGF to the EU's EDS in a safe and reliable manner; and

   f. Additional evaluations at the expense of the Interconnection Customer, when an Interconnection Customer requests that the interconnection Feasibility Study evaluate multiple potential points of interconnection.

6. An interconnection System Impact Study shall evaluate the impact of the proposed interconnection on both the safety and reliability of the EU's EDS. The study shall identify and detail the system impacts that result when the proposed DGF is interconnected without project or system modifications, focusing on the Adverse System Impacts identified in the interconnection Feasibility Study and potential impacts including those identified in the Scoping Meeting. The study shall consider all generating facilities that, on the date the interconnection System Impact Study is commenced, are directly interconnected with the EU's system, have a pending higher Queue Position to interconnect to the system, and have a signed a DGF Interconnection Agreement.

a. An interconnection System Impact Study shall be performed when the interconnection Feasibility Study identifies a potential distribution system Adverse System Impact. The EU shall send the Interconnection Customer an interconnection System Impact Study agreement within 5 business days of transmittal of the interconnection Feasibility Study report. The agreement shall include an outline of the scope of the study and a good faith estimate of the cost to perform the study. The System Impact Study shall include:

    i. A load flow study;
    ii. Identification of affected systems;
    iii. An analysis of equipment interrupting ratings;
    iv. A protection coordination study;
    v. Voltage drop and flicker studies;
    vi. Protection and set point coordination studies;
    vii. Grounding reviews; and
    viii. Impact on system operation.

b. An interconnection System Impact Study shall consider the following criteria:

    i. A short circuit analysis;
    ii. A stability analysis;
    iii. Alternatives for mitigating Adverse System Impacts on affected systems;
    iv. Voltage drop and flicker studies;
    v. Protection and set point coordination studies; and
    vi. Grounding reviews.

c. The interconnection System Impact Study shall provide the following:

    i. The underlying assumptions of the study;
    ii. The results of the analyses;
    iii. A list of any potential impediments to providing the requested interconnection service;
    iv. Required Distribution System Upgrades; and
    v. A nonbinding good faith estimate of cost and time to construct any required Distribution System Upgrades.

d. The parties shall use an interconnection System Impact Study agreement approved by the Commission.

7. The interconnection Facilities Study shall be conducted as follows:

    a. Within 5 business days of completion of the interconnection System Impact Study, the EU shall send a report to the Interconnection

Customer with an interconnection Facilities Study agreement, which includes an outline of the scope of the study and a nonbinding good faith estimate of the cost to perform the study;

b. The interconnection Facilities Study shall estimate the cost of the equipment, engineering, procurement and construction work including overheads needed to implement the conclusions of the interconnection Feasibility Study and the interconnection System Impact Study to interconnect the DGF. The interconnection Facilities Study shall identify:

   i. The electrical switching configuration of the equipment, including transformer, switchgear, meters and other station equipment;
   ii. The nature and estimated cost of the EU's Interconnection Facilities and Distribution System Upgrades necessary to accomplish the interconnection; and
   iii. An estimate of the time required to complete the construction and installation of the facilities;

c. The parties may agree to permit an Interconnection Customer to separately arrange for a third party to design and construct the required Interconnection Facilities. The EU may review the design of the facilities under the interconnection Facilities Study agreement. When the parties agree to separately arrange for design and construction and to comply with security and confidentiality requirements, the EU shall make all relevant information and required specifications available to the Interconnection Customer to permit the Interconnection Customer to obtain an independent design and cost estimate for the facilities, which shall be built in accordance with the specifications;

d. Upon completion of the interconnection Facilities Study, and with the agreement of the Interconnection Customer to pay for the Interconnection Facilities and Distribution System Upgrades identified in the interconnection Facilities Study, the EU shall provide the Interconnection Customer with a DGF Interconnection Agreement within 5 business days; and

8. When an EU determines, as a result of the interconnection studies conducted under a Level 3 review, that it is appropriate to interconnect the DGF, the EU shall provide the Interconnection Customer with a DGF Interconnection Agreement. If the Interconnection Request is denied, the EU shall provide a written explanation setting forth the reasons for denial;

9. An Interconnection Customer shall have 30 business days from receipt of the DGF Interconnection Agreement, unless another mutually agreeable time frame is

reached, to sign and return the DGF Interconnection Agreement to the EU. If an Interconnection Customer does not sign the DGF Interconnection Agreement within 30 business days, the Interconnection Request shall be deemed withdrawn unless the Interconnection Customer requests in writing, prior to the expiration of the 30 business-day period, to extend the deadline. The EU may not unreasonably deny the request for extension. When construction is required, the interconnection of the DGF shall proceed according to milestones agreed to by the parties in the DGF Interconnection Agreement. The DGF Interconnection Agreement may not be final until:

a. The milestones agreed to in the DGF Interconnection Agreement are satisfied;

b. The DGF is approved by electric code officials with jurisdiction over the interconnection;

c. The Interconnection Customer provides a Certificate of Completion to the EU. Completion of local inspections may be designated on inspection forms used by local inspecting authorities; and

d. The Witness Test was successfully completed per the terms and conditions found in the Agreement.

102 An interconnection System Impact Study is not required when the interconnection Feasibility Study concludes there is no Adverse System Impact, or when the study identifies an Adverse System Impact, but the EU is able to identify a remedy without the need for an interconnection System Impact Study.

103 The parties shall use a form of interconnection Feasibility Study agreement approved by the Commission.

Chapter 08: TECHNICAL STANDARDS

100 The technical standard to be used in evaluating all Interconnection Requests under Level 1, Level 2, and Level 3 reviews, unless otherwise provided for in these procedures, is IEEE Standard 1547. IEEE 1547.2, "Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems," shall be used as a guide (but not a requirement) to detail and illustrate the interconnection protection requirements that are provided in IEEE 1547.

Chapter 09: POINT OF COMMON COUPLING

100 To minimize the cost of interconnecting multiple DGFs, the EU or the Interconnection Customer may propose a single PCC for multiple DGFs located at a single site. If the Interconnection Customer rejects the EU's proposal for a single PCC, the Interconnection Customer shall pay the additional cost, if any, of providing a separate

PCC for each DGF. If the EU rejects the customer's proposal for a single PCC without providing a written technical explanation, the EU shall pay the additional cost, if any, of providing a separate PCC for each DGF.

Chapter 10: RECORDS AND REPORTS

100 An EU shall maintain records of the following for a minimum of 3 years:

1. The total number of and the Nameplate Capacity of the Interconnection Requests received, approved and denied under Level 1, Level 2, and Level 3 reviews;

2. The number of Interconnection Requests that were not processed within the timelines established in this rule;

3. The number of Scoping Meetings held and the number of feasibility studies, impact studies, and facility studies performed and the fees charged for these studies;

4. The justifications for the actions taken to deny Interconnection Requests; and

101 An EU shall provide a report to the Commission containing the information required in paragraphs (a)-(d) above within 90 calendar days of the close of each year.

Chapter 11: INFORMATION FOR PROSPECTIVE INTERCONNECTIONCUSTOMERS

100 An EU shall designate a contact person and contact information on its website and for the Commission's website for submission of all Interconnection Requests and from whom information on the Interconnection Request process and the EU's EDS can be obtained regarding a proposed DGF. The information shall include studies and other materials useful to an understanding of the feasibility of interconnecting a DGF at a particular point on the EU's EDS, except to the extent that providing the materials would violate security requirements or confidentiality agreements, or otherwise would be contrary to Mississippi or federal law and regulations. In appropriate circumstances, the EU may require execution of a confidentiality agreement prior to release of information about the EU's EDS.

101 When the EU determines that an Interconnection Request is complete, a modification of DGF design by the Interconnection Customer other than a Minor Equipment Modification that is not agreed to in writing by the EU shall require submission of a new Interconnection Request.

Chapter 12: ADDITIONAL TECHNICAL REQUIREMENTS

100 DGFs shall be capable of being isolated from the EU. For Level 2 and Level 3 interconnection, the isolation shall be by means of a lockable, visible-break isolation device whose status is clearly indicated and is accessible by the EU. The isolation device shall be installed, owned and maintained by the owner of the DGF and located between the DGF and the PCC. A draw-out type circuit breaker with a provision for padlocking at the draw-out position can be considered an isolation device for purposes of this requirement. A draw-out type circuit breaker has a switching device capable of making, carrying and breaking currents under normal and abnormal circuit conditions such as those of a short circuit. A draw-out circuit breaker can be physically removed from its enclosure creating a visible break in the circuit. For the purposes of these regulations, the draw-out circuit breaker shall be capable of being locked in the open, draw-out position. Level 1 interconnections do not require an external isolation device.

101 A Level 2 or Level 3 Interconnection Customer may elect to provide the EU access to an isolation device that is contained in a building or area that may be unoccupied and locked or not otherwise readily accessible to the EU, by installing a lockbox provided by the EU that shall provide ready access to the isolation device. The Interconnection Customer shall install the lockbox in a location that is readily accessible by the EU, and the Interconnection Customer shall permit the EU to affix a placard in a location of its choosing that provides clear instructions to EU operating personnel on access to the isolation device. In the event that the Interconnection Customer fails to comply with the terms of this subsection and the EU needs to gain access to the isolation device, the EU shall not be held liable for any damages resulting from any necessary EU action to isolate the Interconnection Customer.

102 Any metering necessitated by a DGF shall be installed, operated and maintained in accordance with applicable tariffs. Any such metering requirements shall be clearly identified as part of the DGF Interconnection Agreement executed by the Interconnection Customer and the EU.

103 The EU shall design, procure, construct, install, and own any Distribution System Upgrades. The actual cost of the Distribution System Upgrades, including overheads, shall be directly assigned to the Interconnection Customer. The Interconnection Customer may be entitled to financial contribution from any other EU customers who may in the future utilize the upgrades paid for by the Interconnection Customer. Such contributions shall be governed by the rules, regulations, and decisions of the Commission.

104 The Interconnection Customer shall design its DGF to maintain a composite power delivery at continuous rated power output at the Point of Common Coupling at a power factor within the power factor range required by the EU's applicable tariff for a comparable load customer. EU may also require the Interconnection Customer to follow a voltage or VAR schedule if such schedules are applicable to similarly situated generators in the control area on a comparable basis and have been approved by the Commission. The specific requirements for meeting a voltage or VAR schedule shall be clearly specified in Attachment 3 of the "Mississippi Distributed Generator Interconnection Rule Level 2 and Level 3 Agreement for Interconnection of Distributed Generator Facilities." Under no circumstance shall these additional requirements for voltage support or reactive power exceed the normal operating capabilities of the DGF. The requirements in this paragraph may be additional to requirements in IEEE 1547.

Chapter 13: DISPUTES

100 A party shall attempt to resolve all disputes regarding interconnection as provided in the MDGIR promptly, equitably, and in a good faith manner.

101 When a dispute arises, a party may seek immediate resolution through complaint procedures available through the Commission by providing written notice to the Commission and the other party stating the issues in dispute.

102 When disputes relate to the technical application of the MDGIR, the Commission may designate a technical consultant to resolve the dispute. Upon Commission designation, the parties shall use the technical consultant to resolve disputes related to interconnection. Costs for dispute resolution conducted by the technical consultant shall be established by the technical consultant and subject to review by the Commission. The EU and the Interconnection Customer shall share equally the costs of an outside arbitrator unless they mutually agree to a different payment arrangement.

103 Pursuit of dispute resolution shall not affect an Interconnection Customer with regard to consideration of an Interconnection Request or an Interconnection Customer's Queue Position.