

COMMITMENT, OPERATIONS, AND DISPATCH AGREEMENT

Among

ENTERGY ARKANSAS, INC.

ENTERGY GULF STATES LOUISIANA, L.L.C.

ENTERGY LOUISIANA, LLC

ENTERGY MISSISSIPPI, INC.

ENTERGY NEW ORLEANS, INC.

ENTERGY TEXAS, INC.

ENTERGY SERVICES, INC.

DATE

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ENTERGY SERVICES, INC.

THIS AGREEMENT, first made and entered into on the ___ day of _____, is by and among Entergy Arkansas, Inc., hereinafter called "EAI"; Entergy Gulf States Louisiana, L.L.C., hereinafter called "EGSL"; Entergy Louisiana, LLC, hereinafter called "ELL"; Entergy Mississippi, Inc., hereinafter called "EMI"; Entergy New Orleans, Inc., hereinafter called "ENOI"; and Entergy Texas, Inc., hereinafter called "ETI" (collectively with EAI, EGSL, ELL, EMI, and ENOI hereinafter called the "Parties", and, individually, a "Party").

WITNESSETH

- 0.01 WHEREAS, EAI, EGSL, ELL, EMI, ENOI, and ETI (collectively, hereinafter called the "Companies" and, individually, a "Company"), are the owners and operators of electric generation, transmission and distribution facilities with which they are engaged in the business of manufacturing, generating, transmitting and selling electric energy to the general public and to other electric distributing agencies; and
- 0.02 WHEREAS, Entergy Services, Inc. ("ESI" or "Services") is an associated service company acting as agent for the Companies under the terms of the Middle South Utilities System Agency Agreement and the Middle South Utilities System Agency Coordination Agreement, each dated as of the 11th day of December 1970; and
- 0.03 WHEREAS, the parties to this Agreement recognize that Services provides certain services to the Operating Companies and may perform some of the services described herein; and

- 0.04 WHEREAS, the Companies and Services were previously parties to a contract, dated as of the 23rd of April, 1982 (hereinafter called the "System Agreement"), under which they coordinated their planning and operations; and
- 0.05 WHEREAS, there was substantial litigation under the System Agreement that resulted in the Federal Energy Regulatory Commission ("FERC") imposing a standard of rough equalization of production costs and such litigation created continuing controversy and uncertainty that the Parties seek to avoid; and
- 0.06 WHEREAS, the Companies agreed to terminate the System Agreement and replace it with this Commitment, Operations, and Dispatch Agreement (the "CODA") to provide greater certainty as to the Parties' rights and obligations through a limited form of coordination;
- 0.07 WHEREAS, the Parties agree that the CODA is intended:
- to obtain the efficiencies of a larger voluntary coordinated bulk power electric system, including:
 - the energy savings associated with the joint commitment and dispatch of a larger fleet of generating units, and
 - the sharing of capacity reserves that would allow each company to achieve the same level of reliability at a lower level of owned or controlled generation than if operating outside this Agreement;
 - to require each Company to plan for and provide its own resources to meet the capacity needs of each Companies' customers' Loads,
 - to result in each Company's realizing the benefits and costs of its own generation planning decisions, and
- 0.08 WHEREAS, the Parties further agree that the CODA:
- Does not include any intent to equalize, or roughly equalize, production costs of the Companies,

- Does not require joint planning of the Companies' generation resources on a collective basis,

0.09 WHEREAS, the Parties further agree that certain limitations must be placed on the ability of individual Operating Companies to make independent short-term purchases and sales so as to enable a coordinated commitment and dispatch, but such limitations are intended to enable a coordinated operation of the electrical system and do not create any joint planning obligations.

NOW THEREFORE, the Parties hereto mutually understand and agree as follows:

ARTICLE I

TERM OF AGREEMENT

- 1.01 Term of the Agreement: This Agreement shall become effective at the beginning of the first full calendar month following its acceptance by the FERC (the "Effective Date"), subject to the condition precedent set forth in Section 1.02, but in no event shall such Effective Date be earlier than December 1, 2013. After the Effective Time, the Agreement shall continue in full force and effect until terminated in accordance with Section 1.03.
- 1.02 Condition Precedent: This Agreement shall not become effective unless accepted without change by the FERC. If the FERC makes any change, or imposes any condition on its acceptance, each Company must provide written notice to all the other Companies as to whether it will execute the Agreement as so amended or conditioned by the FERC within 60 calendar days of a final FERC order. If all Companies, or if all Companies except EAI, do not provide notice to the other Companies that such Company will execute this Agreement within such 60-calendar day period, the Agreement shall be null and void.
- 1.03 Termination Provisions: After the Effective Date, a Company may withdraw from this Agreement only under the conditions specified as follows. In the event a Company so

withdraws, the Agreement shall remain in full force and effect with respect to the remaining Companies:

- a) Upon 90 days written notice to all the other Companies if the FERC or a Court, subsequent to acceptance of the Agreement, makes a modification, imposes a condition, or otherwise takes action that, in the sole discretion of such Company, such Company determines is adverse to it and warrants termination of its participation in this Agreement; or
- b) Upon no less than 12 months prior to May 1 of the calendar year in which that party intends to terminate its participation.

1.04 No Termination Payments: In the event a Company provides notice of termination of its participation in this Agreement in accordance with Section 1.03, it shall remain liable only for payments due by or accrued with respect to it under the provisions of this Agreement prior to the termination, but in no event shall any Company be liable for any termination fee or other payment as a condition of termination of participation in this Agreement or be obligated to sell, convey, dispose of or transfer any assets or rights, or any portion thereof, as a condition of termination of its participation in this Agreement.

ARTICLE II DEFINITIONS

For the purpose of this Agreement and of the Service Schedules which are a part hereof, the definitions set forth in Appendix A shall apply:

ARTICLE III OBJECTIVES AND OBLIGATIONS

3.01 Objectives: The Agreement provides for a limited form of coordination among the Companies to (a) gain efficiencies of operation through the joint dispatch and commitment of generation, and (b) achieve a lower System planning reserve margin than would otherwise be obtained through this CODA through the independent procurement of reserves;

provided, however, that nothing in this Agreement shall be construed as providing for the centralized planning of Generation Resources or the rough equalization of production costs.

- 3.02 Procurement of Generation: Each Company is obligated to procure such Generation Resources as are necessary and appropriate to serve its Total Company Load. If any Company does not procure sufficient Generation Resources to serve its Total Company Load in accordance with Section 3.05, the System Dispatcher shall procure the necessary additional Resources pursuant to Service Schedule No. 5. Two or more Companies may choose to coordinate their procurement of Generation Resources, but nothing in this Agreement shall obligate them to do so.
- 3.03 Nomination of Resources: Each Company shall furnish the Parties, through written notice to the CODA Management Committee as specified in Section 3.06, a designation of the Generation Resources that such Company owns, or has available to it under contract, and will place under the control of the System Dispatcher.
- 3.04 Provision of Load Forecasts: By February 1 of each calendar year, each Company shall furnish to the other Companies, through written notice to the CODA Management Committee, a forecast of its electric energy and demand requirements for each calendar month in the following calendar year that are to be served by the Resources placed under the control of the System Dispatcher (the "Requirements Forecast").
- a) The Requirements Forecast shall include the following information:
 - i) The aggregate amount of energy (in MWh) that a Company expects to require to be delivered to meet its obligations ("Monthly Energy Requirements"); and
 - ii) The maximum amount of power (in MW) that a Company expects to require to meet its obligations ("Monthly Peak Demand").
 - b) The CODA Management Committee may revise or expand the information required to be included in the Requirements Forecast.

- c) The CODA Management Committee shall, by March 1 of each calendar year, prepare a load and Energy forecast for all Companies on a combined basis for each calendar month of the following calendar year.
- 3.05 Generation Resource Obligation: The CODA Management Committee shall, by April 1st of each calendar year, determine the System's Generation Resource Obligation ("GRO") for each calendar month of the following calendar year by increasing the System Total Load by a Planning Reserve Margin established by the CODA Management Committee. Each Company's Generation Resource Obligation shall be determined by multiplying (a) such Company's percentage contribution to the monthly forecasted peak load, by (b) the System's Generation Resource Obligation for the calendar month.
- 3.06 Designation of Generation Resources: Each Company must designate Generation Resources with sufficient Capability to meet or exceed its Generation Resource Obligation. The designation of such Resources shall be completed in accordance with the following schedule:
- a) By October 1 of each Calendar Year – 100% of the GRO in the months of January, February, March and April in the next Calendar Year
 - b) By February 1 of each Calendar Year – 100% of the GRO in the months of May, June, July, August, and September in the current Calendar Year.
 - c) By July 1 of each Calendar Year – 100% of the GRO in the months of October, November, and December in the current calendar year.
- 3.07 Qualification of Generation Resource: When a Company designates its Generation Resources to the CODA Management Committee, it must supply the following information for each Resource:

- a) Confirmation that the Generation Resource is designated as a "Network Resource" under the Entergy Open Access Transmission Tariff or any successor thereto for the period for which it is qualified.
- b) Confirmation that the Company has the right to control capacity and energy from the resource or that the output of the resource is dedicated to the Company.
- c) The operating characteristics of the Resources including:
 - i) Name of the Resource;
 - ii) Maximum dependable capability in each calendar month;
 - iii) Minimum operating level;
 - iv) Fuel supply arrangements;
 - v) Automatic Generation Control characteristics;
 - vi) Length of time required to start and synchronize to the grid;
 - vii) Minimum shutdown time; and
 - viii) Any other Resource-specific information deemed appropriate by the CODA Management Committee)
- d) The CODA Management Committee will review the characteristics submitted by each Company for each Resource. The System Dispatcher will provide technical assistance and recommendations to the CODA Management Committee in its review of these characteristics.

3.08 Disqualification of a Generation Resource: If the CODA Management Committee determines that a Company has not provided the required information for a Generation Resource, or determines that Generation Resource does not otherwise meet the criteria in Section 3.07, the CODA Management Committee may reject the Generation Resource and require the Company to replace the Generation Resource within 30 calendar days. A Generation Resource for which the CODA Management Committee has accepted the required information shall be a Qualified Resource for the purposes of this Agreement.

3.09 Records and Reports: The CODA Management Committee shall direct that such records as may be necessary for the efficient administration of the Agreement be kept, and shall make

such records available for review to any Company upon written request directed to the Secretary of the CODA Management Committee. Each Company shall make all reports requested by the CODA Management Committee within the time prescribed in such request.

- 3.10 Regulatory Authorization: Each Company shall use good faith, commercially reasonable efforts to seek any necessary regulatory authorization for this Agreement and the performance of its obligations thereunder.
- 3.11 Service Schedules: The basis of compensation for the capacity and energy provided or supplied by a Company to another Company or Companies under this Agreement, or the equalization of costs of the bulk transmission system shall be in accordance with arrangements agreed upon from time to time among the Companies in the form of Service Schedules (collectively, the "Service Schedules") and, individually, a "Service Schedule"). Each Service Schedule, when signed by all the Parties hereto, and approved or accepted for filing by the appropriate regulatory authority, shall be attached to and become a part of this Agreement.
- 3.12 Measurements: All capacity and energy measurements shall be made at or corrected to the points of interconnection unless otherwise agreed to by the CODA Management Committee.
- 3.13 Billings: Bills for services rendered hereunder ("Inter-Company Bills" or "ICB") shall be calculated in accordance with the applicable Service Schedule. Billings and payments shall be issued in accordance with the schedule established by the CODA Management Committee, and shall be issued on the fifth working day of the month following that in which such service was rendered and shall be payable on or before the 15th day of such month. Beginning on the fifth working day after the due date established by the CODA Management Committee, interest shall accrue on any balance due at the rate as determined in Section 35.19a (2)iii of the FERC Regulations, or at such other rate established by the CODA Management Committee.

ARTICLE IV

COMPOSITION AND DUTIES OF THE CODA MANAGEMENT COMMITTEE

- 4.01 CODA Management Committee: A CODA Management Committee shall be responsible for the oversight and executive administration of this Agreement.
- 4.02 Representation: The CODA Management Committee shall consist of a representative of each Company (the "Company Representative" and, collectively, the "Company Representatives"). Each Company Representative shall be designated by the Chief Executive Officer of such Company. Such designation shall be made by written notice to the Secretary of the CODA Management Committee with copies to each of the other Parties. A Company may change its designated Company Representative at any time by written notice to the Secretary of the CODA Management Committee and each of the other Parties.
- 4.03 Officers: The CODA Management Committee shall have the following officers with duties as designated:
- a) Chairman - The Chairman shall issue calls for and shall preside at meetings of the CODA Management Committee. The Chairman shall have responsibility for the general coordination of the CODA Management Committee functions among the various members.
 - b) Vice Chairman - The Vice Chairman shall perform the duties of the Chairman in the absence or incapacity of the Chairman.
 - c) Secretary - The Secretary shall be responsible for keeping the minutes of the meetings of the CODA Management Committee and for preparing copies thereof and for distributing them to the Companies. The Secretary shall be designated by the CODA Management Committee, and shall serve at the discretion of the CODA Management Committee.
- 4.04 Elections: The Chairman and Vice Chairman positions shall be filled by members of the CODA Management Committee and shall be elected by a majority vote of the CODA Management Committee. Each shall serve a term of one year. The Chairman shall appoint the Secretary and such person is not required to be a member of the CODA Management Committee.

- 4.05 Meeting Dates: The CODA Management Committee shall hold meetings at least quarterly. A meeting may be called by the Chairman or three members of the CODA Management Committee.
- 4.06. Minutes: The Secretary shall keep minutes of the CODA Management Committee's proceedings.
- 4.07 Voting Rights: Each Company represented on the CODA Management Committee will have one vote.
- 4.08 Decisions: All decisions of the CODA Management Committee shall be by a majority vote of the CODA Management Committee members.
- 4.09 Attendance at Meetings: Each Company shall be represented at each CODA Management Committee meeting by its Company Representative or a proxy designated by such Company Representative or the chief executive officer of such Company. Such proxy member need not be an employee of the Company represented. Proxies must be provided in writing to the Secretary of the CODA Management Committee. The Chairman shall establish rules regarding attendance and participation in CODA Management Committee meetings.
- 4.10 Duties: The CODA Management Committee shall:
- a) Establish the policies and procedures for:
 - i) Outage Scheduling;
 - ii) Unit Commitment;
 - iii) Economic Dispatch;
 - iv) Short-term Purchased Power;
 - v) Short-term Fuel Supply; and
 - vi) Short-term Joint Account Sales.
 - b) Approve the Requirements Forecast submitted by each Company and develop a consolidated Requirements Forecast.
 - c) Approve the operating parameters of the designated Generation Resources.
 - d) Establish an annual Planning Reserve Requirement.
 - e) Approve the methodology for the calculation of the System Hourly Avoided Cost.

- f) Provide such oversight of the functions and duties established by this Agreement as is necessary or appropriate, including, but not limited to, the functions and duties of the Dispatcher and Inter-Company Billing.
- 4.11 Joint Account Purchases: Under the direction of the CODA Management Committee, the System Dispatcher may purchase Energy under economic dispatch or emergency conditions, in accordance with Article VI of this Agreement, for the joint account of all the Companies. All economy and emergency energy purchases with a term of six months or less shall be allocated to each Company in proportion to its Responsibility Ratio.
- 4.12 Joint Account Sales: Sales of Capacity and Energy at wholesale to unaffiliated third parties for which any Company does not wish to assume sole responsibility, shall, with the consent of or under conditions specified by the CODA Management Committee, be made for the joint account of all the Companies. All sales of energy to unaffiliated third parties made for a term of one month or less shall be made for the Joint Account of all of the Companies. Revenues from the sale shall be allocated among the Operating Companies based on Responsibility Ratio and the obligation to provide the energy shall be allocated among the Operating Companies based on Responsibility Ratio and included in each Operating Company's Load for purposes of Service Schedule-2.
- 4.13 Expenses of Committee: Each Company shall pay the expenses of its Company Representative on the CODA Management Committee. Any other expenses of the CODA Management Committee shall be prorated among the Companies on a Responsibility Ratio basis.

ARTICLE V SYSTEM DISPATCHER

- 5.01 System Dispatcher: Under general direction of the CODA Management Committee, the System Dispatcher shall operate a dispatch and operations center properly equipped and staffed to commit and dispatch the Energy supply Resources of the Companies in an efficient, economical, and reliable manner as provided in this Agreement.

5.02 Duties: The System Dispatcher shall:

- a) Develop and implement Daily Operating Plans;
- b) Dispatch the Companies' collective Energy supply Resources in real time to provide reliable service to the Companies' customers at a reasonable cost;
- c) Determine the availability of joint account Energy for purchase from or sale to outside systems under effective contracts and arrange for and schedule such transactions;
- d) Procure and arrange for the delivery of the fossil fuels necessary to operate the Companies' supply resources;
- g) Coordinate the operation of communication facilities owned or leased by the Companies to provide the communication essential to the safe, reliable and economical operation of the System; and
- h) Maintain such records and prepare such reports as the CODA Management Committee may designate.

5.03 Daily Operations Plan: The System Dispatcher shall establish, for each Day, a Daily Operations Plan that identifies those Generation Resources that will be relied upon to supply reliable service to the System Load.

5.04 Economic Dispatch: The collective Resources of all of the Companies shall be dispatched using a security constrained economic dispatch. The Companies' Resources shall be operated in a manner that provides the lowest reasonable cost of Energy for all of the Companies collectively, subject to the requirements and/or constraints imposed by the need to comply with the requirements imposed by FERC, national and regional reliability organizations, transmission operations, and the reliability and security of the integrated electrical system. As a result of these joint operations, there may be hours in which the Energy supply costs for any individual Company are greater than the costs that such Company might incur in stand-alone operations. It is also recognized by the Companies that, because of such economic dispatch, a Company may not, at all times, be supplying the Energy requirements of its customers, but may be taking energy from the Resources of the other Companies or supplying energy to the other Companies.

- 5.05 Communication and Other Facilities: The Companies shall provide communication and other facilities, determined by the CODA Management Committee at the recommendation of the System Dispatcher to be necessary for metering, control, protection and dispatch of the production and transmission facilities, and for such other purposes as may be necessary or desirable for the operation of the Companies' electrical systems.
- 5.06 Expenses: All expenses of the Dispatcher shall be paid by Entergy Services and billed monthly to each Company in accordance with the procedures established by the CODA Management Committee.

ARTICLE VI
MISCELLANEOUS

- 6.01 Independent Contractors: It is agreed among the Companies that by entering into this Agreement, the Companies shall not become or be deemed to become partners, but as to each other and to third persons, the Companies shall remain independent contractors in all matters relating to this Agreement. *[The implications of this section are currently under review from commercial / transactional counsel]*
- 6.02 Successors and Assigns: This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective Parties hereto, but shall not be assignable by any Party without the written consent of the other Parties, except upon foreclosure of a mortgage or deed of trust.
- 6.03 Amendment: This Agreement may be changed, amended, or supplemented, only by an instrument in writing, signed by all the Parties. Nothing contained herein shall be construed as affecting in any way the right of any Party to unilaterally make application to the FERC under Sections 205 and 206 of the Federal Power Act to change or modify any provision of this Agreement.

It is the intent of the Parties that the standard of review that the FERC shall apply when acting on proposed modifications to this Agreement either on FERC's own motion or

on behalf of a signatory or non-signatory, shall be the "just and reasonable" standard of review rather than the "public interest" standard of review.

6.05 Notices: All notices and communications required or permitted to be given hereunder shall be in writing and shall be delivered personally, or sent by overnight courier, or sent by facsimile transmission (provided any such facsimile transmission is confirmed either orally or by written confirmation), addressed to the appropriate Party at the address for such Party shown below or at such other address as such Party shall have theretofore designated by notice delivered in the manner set forth in this Section 6.05 to the Party giving such notice:

If to EAI:

[Address]

[Attention:]

[Tel:]

[Fax:]

If to EGSL:

[Address]

[Attention:]

[Tel:]

[Fax:]

If to ELL:

[Address]

[Attention:]

[Tel:]

[Fax:]

If to EMI:

[Address]

[Attention:]

[Tel:]

[Fax:]

If to ENOL:

[Address]

[Attention:]

[Tel:]

[Fax:]

If to ETI:

[Address]

[Attention:]

[Tel:]

[Fax:]

If to Services:

[Address]

[Attention:]

[Tel:]

[Fax:]

- 6.06 Waivers: Any waiver at any time by a Party of its rights with respect to a default by any other Party under this Agreement, shall not be deemed a waiver with respect to any subsequent default. Any of the terms, covenants, rights, or conditions hereof may be waived only by a written instrument executed by or on behalf of the Party hereto waiving compliance. No waiver by any Party of any right or condition, or any breach of or default under any term or covenant contained in this Agreement, in any one or more instances, shall be deemed to be or construed as a further or continuing waiver of any such right or condition or breach or default or a waiver of any other right or condition or of any breach of or default under any other term, covenant, right or condition. The rights of Parties under this Agreement shall be cumulative, and the exercise or partial exercise of any such right shall not preclude the exercise of any other right.

- 6.07 Governing Law: This Agreement shall be governed by and construed in accordance with the laws of the state of [_____].
- 6.08 Counterparts/Facsimile: This Agreement may be executed in any number of counterparts, and each such counterpart hereof shall be deemed to be an original instrument, but all of such counterparts shall constitute for all purposes one agreement. Any signature hereto delivered by a Party by facsimile transmission shall be deemed an original signature hereto.
- 6.09 Severability: If any term or other provision of this Agreement is invalid, illegal, or incapable of being enforced by any rule of law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in any adverse manner to any Party. Upon such determination that any term or other provision is invalid, illegal, or incapable of being enforced, the Parties hereto shall negotiate in good faith to modify this Agreement so as to reflect the original intent of the Parties as closely as possible in an acceptable manner, subject to the acceptance or approval of the FERC.
- 6.10 Responsibility for Loss or Damage: Each Company shall defend, indemnify, and save harmless the other Companies against liability, loss, costs and expenses on account of any injury or damage to persons or property occurring on or in connection with its facilities on its side of any of the points of interconnection, except to the extent such injury or damage was caused by the gross negligence or willful misconduct of another Company, its agents or employees. *[The implications of this section are currently under review from commercial / transactional counsel]*

SERVICE SCHEDULE No. 1

EXCHANGE OF FLEXIBLE ENERGY AMONG THE COMPANIES

Capitalized terms used in this Service Schedule No. 1 and not otherwise defined herein shall have the same meanings herein as ascribed thereto in the Agreement.

10.01 Purpose: The purpose of this Service Schedule is to provide the method for quantifying and pricing the Flexible Energy exchanged among the Companies as a result of the joint operation of supply Resources.

10.02 Deployed Flex and Allocated Flex Requirement

- a) Deployed Flex is calculated for each hour of the Billing Period. Deployed Flex is the sum of the Resource Flex (expressed in MW) available in each hour for each of a Company's Generation Resources included in the Daily Operation Plan. The amount of Deployed Flex provided by each Company shall be aggregated and referred to as a Company's "Actual Deployed Flex". The sum of all of the Companies' Actual Deployed Flex is referred to as the "Total Deployed Flex".
- b) The Allocated Flex Requirement ("AFR") is the portion of the Total Deployed Flex for which each Company is responsible. It is calculated for each Company c as follows:

$$AFR_c = \text{Flex Allocation Factor}_c * \text{Total Deployed Flex}$$

- c) A Flex Allocation Factor ("FAF") is determined for each Company for each Commitment Period, calculated as follows:

$$FAF_c = \frac{(MHQP_{ci} + DLS_{ci} + SR_{ci})}{(MHQP_{si} + DLS_{si} + SR_{si})}$$

Where:

FAF_p : Flex Allocation Factor for Company c

i : Indicates the day in the Commitment Period on which the sum of $(MHQP_{si} + DLS_{si})$ was the highest.

c : Denotes Company

s : Denotes total for all the Companies

$MHQP_{si}$: the Maximum Hourly QF Put on day i of the Commitment Period. HQP_{si} is the sum of the amount of Energy put to

each of the Operating Companies in any given hour, excluding Energy produced by a QF but scheduled by the System Dispatcher. $MHQP_{sj}$ is the HQP_{sj} for the hour in the Commitment Period for which the sum of ($MHQP_{sj} + DLS_{sj}$) was the highest. .

$MHQP_{ci}$: the quantity of Energy put to Company c coincident with the $MHQP_{sj}$

DLS_{sj} : the Daily Load Swing on day i in the Commitment Period. Daily Load Swing ("DLS") is the difference between the highest and lowest hourly Total Loads during calendar day i for all the Companies.

DLS_{ci} : the Daily Load Swing at Company c coincident with DLS_{sj} .

SR_{sj} : the Total Spinning Reserves required on day i in the Commitment Period.

SR_{ci} : Company c 's allocated share of SR_{sj} , allocated using Company c 's relative share of the total amount of Energy delivered to customers during the Commitment Period.

10.03 Exchange of Flexible Energy

- a) For each and every hour of a Commitment Period, each Company's Deployed Flex is compared to its Allocated Flex Requirement.
- b) If a Company's Deployed Flex is less than its Allocated Flex Requirement, that Company is "Short" and must purchase energy from the Flexible Energy Exchange in the hour (as denoted in 10.04 (d) below).
- c) If a Company's Deployed Flex is greater than its Allocated Flex Requirement, that Company is "Long" and must sell an amount of energy to the Flexible Energy Exchange in the hour (as denoted in 10.04 (b) below).

10.04 Assignment of Resources to the Flexible Energy Exchange

a) Determination of the Resources Supplying Energy to the Flexible Energy Exchange

The determination of the resources that are supplying the Energy into the Flexible Energy Exchange is made for each hour for each Company with Flex Surplus in that hour. For each such Company, an hourly Resource Stack is created by stacking the Deployed Flex of the Company in cost order, based on the Flex Comparison Rate of each Resource, calculated on an hourly basis pursuant to Section 10.05 of this Service Schedule, with the lowest cost Resource at the bottom of the stack and the highest cost Resource at the top. Beginning with the Resource at the top of the stack, Resources, including partial Resources, are removed from the Company stack in decreasing cost order until the Company's Flex Surplus is eliminated (i.e. the Company's Deployed Flex is equal to its Allocated Flex Requirement). The Resources removed from the Company's stack are the Resources that are used to determine the amount and cost of Energy sold to the Flexible Energy Exchange.

b) Energy Sold to Flexible Energy Exchange

For every Resource assigned to the Flexible Energy Exchange, the Energy produced by that resource when operating at its Minimum Operating Level is sold to the Flexible Energy Exchange. If only a portion of a Resource is assigned to the Flexible Energy Exchange, the same proportion of the Energy produced by the Resource when operating at its Minimum Operating Level is sold to the Flexible Energy Exchange.

c) Price of Energy Sold to the Flexible Energy Exchange

The price of Energy sold to the Flexible Energy Exchange shall be calculated independently for each Resource sold to the Flex Exchange pursuant to the formula below:

Flex Total Cost_{rh}

$$\text{Flex Energy Rate}_{rh} = \frac{\text{Flex Total Cost}_{rh}}{\text{Minimum Operating Level}_{rh}}$$

Where:

r : Denotes Resource

h : Denotes hour of year.

"Flex Total Cost_{rh}" is the total cost incurred to use Resource Flex from Resource r in hour h . It is calculated for each Resource in each hour pursuant to the following formula:

$$\text{"Flex Total Cost"} = \text{Flex Commitment Cost} + \text{Flex Dispatch Cost}$$

Where:

$$\text{"Flex Commitment Cost"} = [(\text{MOLFC} * \text{UFC}) + \text{UEA}] * \text{MOL}$$

Where:

"MOLFC" = Minimum Operating Level Fuel Consumption, expressed on a mmBtu basis

"UFC" = Unit Fuel Cost. Estimated cost of fuel delivered to the Resource, expressed on a \$/mmBtu basis, plus any taxes or surcharges related to the consumption of the fuel, expressed on a \$/mmBtu basis.

"UEA" = Unit Energy Adder. O&M Adder plus any taxes, environmental allowance costs, or other costs directly related to the production of Energy from a Resource not otherwise included in the Unit Fuel Cost, expressed on a \$/MWh basis. The O&M Adder is calculated annually for each Company and is equal to the sum of the costs for the generating plants that include Resources that provide Resource Flex, as recorded in Form 1 Accounts 500, 502, 503, 504, 505, 506, 507, 510, 511, 512, 513 and 514 in the

previous calendar year divided by net steam generation from those same plants for the previous calendar year.

“MOL” = Minimum Operating Level

$$\text{“Flex Dispatch Cost”} = \text{ABS} [[(\text{ACDL} - \text{ADL}) * \text{HAC}] - [(\text{ACOLFC} - \text{AOLFC}) * \text{UFC} + (\text{ACDL} - \text{DL}) * \text{UEA}]]$$

Where:

“ACDL” = Avoided Cost Dispatch Level, expressed in MW.

where:

$$\text{ACDL} = [1 / (2 * C)] * [(\text{HAC} - \text{UEA}) / \text{UFC} - B]$$

“B Component” and “C Component” are the variables B and C in the equation representing the Input/Output (“I/O”) curve of the Resource:

$$A + B * \text{Output Level} + C * \text{Output Level}^2$$

“ADL” = Actual Dispatch Level. Equals the actual output level, expressed in MW, of the Generation Resource in the clock hour.

“ACOLFC” = Avoided Cost Operating Level Fuel Consumption, expressed on a mmBtu basis

“AOLFC” = Actual Operating Level Fuel Consumption, expressed on a mmBtu basis

“Incremental Cost” = UFC * Incremental Heat Rate + UEA

d) Energy Purchased from the Flexible Energy Exchange

The Energy purchased by a Company from the Flexible Energy Exchange is equal to (i) the ratio of the Company's Flex Deficiency to the Total Flex Surplus, multiplied by (ii) the total Energy sold to the Flexible Energy Exchange.

e) Price of Energy Purchased from Flexible Energy Exchange

The price of Energy purchased from the Flexible Energy Exchange is equal to (i) the total payments made to the Companies that sold Energy to the Flexible Energy Exchange in the hour, divided by (ii) the total energy sold to the Flexible Energy Exchange.

10.05. Calculation of Flex Comparison Rate

a) The "Flex Comparison Rate", expressed in terms of \$/MW, is the rate used to rank Resource Flex for purposes of determining the Energy sold to the Flexible Energy Exchange. It is calculated for each Resource that provides Resource Flex in the Daily Operations Plan pursuant to the following formula:

$$\text{Flex Comparison Rate}_{rh} = \text{Flex Net Cost}_{rh} / \text{Resource Flex}_{rh}$$

Where:

r : Denotes Resource

h : Denotes hour of year.

"Resource Flex" is the difference between the Minimum Operating Level and Maximum Operating Level of the Generation Resource less any portion of that range at which the Generation Resource cannot be operated at a stable level, as determined pursuant to procedures determined by the CODA Management Committee. [move below description of flex net cost]

$$\text{Flex Net Cost} = \text{Flex Total Cost} - (\text{MOL} * \text{HAC})$$

Where:

Hourly Avoided Cost (“HAC”) is as defined in Appendix A.

Minimum Operating Level (“MOL”) is the lowest level at which a Generation Resource may be operated in a stable manner.

SERVICE SCHEDULE No. 2
EXCHANGE OF ECONOMY ENERGY AMONG THE COMPANIES

Capitalized terms used in this Service Schedule No. 2 and not otherwise defined herein shall have the same meanings herein as ascribed thereto in Appendix A.

20.01 Purpose

The purpose of this Service Schedule is to provide the method for determining the quantity and price of Economy Energy exchanged among the Companies as a result of the joint dispatch of supply resources.

20.02 Energy Stack

For each and every hour of a Billing Period, the Energy owned and available to each Company shall be accumulated in individual Energy Stacks for each Company. The Energy included in each stack for each Company shall be the sum of:

- a. The Energy supplied in an hour from each and every Eligible Generation Resource that is owned by that Company, less any Energy from an Eligible Generating Resource that is sold into the Flexible Energy Exchange.
- b) That Company's allocated portion of the Energy from Joint Account Purchases allocated to individual Companies pursuant to Section 4.11 of this Agreement.
- c) The Energy purchased by that Company from the Flexible Energy Exchange.

20.04 Load Stacks

For each and every hour of a Billing Period, a Load Stack shall be calculated for each Company. Each Company's Load Stack shall be the sum of:

- a. That Company's Total Load.
- b. That Company's Responsibility Ratio for the Billing Period immediately preceding the current Billing Period multiplied by the Total Joint Account Load.

20.05 Allocation of Economy Energy

- a) For each and every hour of the billing period, the Load Stack of each Company is compared to the Energy Stack of that Company. If a Company's Energy Stack is greater than that Company's Load Stack, then that Company has excess Energy and is considered to be "Long". If a Company's Energy Stack is less than that Company's Load Stack, then that Company is deemed to be deficient Energy is considered to be "Short".

- b) In each and every hour:
 - i) Companies that have excess Energy must sell the amount of Energy by which they are Long to the Economy Energy Pool, for which they will receive price equal to System Hourly Avoided Cost for each MWh of Energy that they sell to the Economy Energy Pool.
 - ii) Companies that are deficient Energy must purchase Energy from the Economy Energy Pool, for which they will pay a price equal to System Hourly Avoided Cost for each MWh of Energy that they purchase from the Economy Energy Pool.
 - iii) The Energy remaining in the Economy Energy Pool is assigned to supply the Joint Account Load at a cost equal to System Hourly Avoided Cost.
 - iv) Purchases from and sales to the Economy Energy Pool are not discretionary. By entering into this Agreement, a Company must sell its excess Energy to the Economy Energy Exchange in hours in which it is Long and must meet its Energy deficiency with a purchase from the Economy Energy Exchange when it is Short.
 - v) Companies may not engage in wholesale transactions for a term of one week or less for their own account.

SERVICE SCHEDULE No. 3

UNIT POWER PURCHASE

*[NOTE: SS # 3 IS UNDER REVIEW TO ADDRESS ISSUES
RELATED TO STORM COST RECOVERY]*

Capitalized terms used in this Service Schedule No. 3 and not otherwise defined herein shall have the same meanings herein as ascribed thereto in Appendix A.

30.01 Purpose: The purpose of this Service Schedule is to provide the basis for making a unit power purchase among Companies and/or the sale of power purchased by another Company, unless an alternative basis is agreed to by the Parties subject to the approval of the FERC and the regulatory agencies of the purchasing and selling Companies under otherwise applicable law and which provides a lower monthly capacity charge than the charge determined pursuant to Section 30.06 or Section 30.09 of this Service Schedule No. 3.

30.02 Designated Generating Unit

- (a) A "Designated Generating Unit" shall be any Generating Unit from which the unit power purchase is made under Section 30.01 that is mutually agreed upon by the purchaser and the seller.
- (b) Any Company that makes a unit power purchase of a portion of Capability shall be entitled to receive each hour, the same portion of the total Energy generated by the Designated Generating Unit. Such Energy shall be purchased at the cost of fuel consumed per kWh in accordance with Section 30.09(a) and will be treated in the same manner as any other Energy available to the purchasing Company.

30.03 Capability Payment

For the Capability purchased in accordance with Section 30.02, the Company making the sale shall receive, from the Company making the purchase, a monthly payment determined in accordance with the method described in Section 30.06 hereinafter.

The monthly capability payment to be received by a Company shall be determined by multiplying the kW of Capability sold from its Designated Generating Unit by a charge per kW-month as defined below.

30.04 Investment in Designated Generating Unit (DGURB)

For the purpose of calculating the Monthly Capacity Charge under Section 30.06, the investment in the Designated Generating Unit (based on the FERC's Uniform System of Accounts prescribed for the Public Utilities and Licensees) shall be:

$$\begin{aligned} \text{DGURB} &= \text{Designated Generating Unit Rate Base} \\ \text{DGURB} &= \text{DGUPTPLT} + \text{DGUCME} - \text{DGUDR} + \text{DGUFINV} - \text{DGUADIT} + \\ &\quad [(\text{GPLT} - \text{GDR} + \text{IPLT} - \text{IAA}) * (\text{DGUL} / \text{LXAG})] + [(\text{MS} + \text{PP}) * \\ &\quad (\text{DGUPLT} / \text{PLT})] \end{aligned}$$

- (a) The cost of the Designated Generating Unit included in FERC Plant Accounts 310 through 346; the cost for step-up transformers, circuit breakers, switching equipment, etc. included in FERC Plant Account 353 which are required to connect the Designated Generating Unit to the transmission system (DGUPTPLT),
- (b) Plus Coal Mining Equipment in FERC Plant Account 399 directly associated with the Designated Generating Unit (DGUCME),
- (c) Less the Accumulated Provision for Depreciation (consistent with the accounting relating to Statement of Financial Accounting Standards (SFAS) 143 approved by the retail regulator having jurisdiction over the Designated Generating Unit, unless the FERC determines otherwise) associated with items (a) and (b) above, as recorded in FERC Account 108, excluding Nuclear Decommissioning Trust Fund Balances, if applicable (DGUDR),
- (d) Plus Fuel Inventory for the Designated Generating Unit, if applicable, in FERC Accounts 151 and 152 (DGUFINV),
- (e) Less net Accumulated Deferred Income Taxes recorded in FERC Accounts 190, 281, 282 and 283 and Accumulated Deferred Investment Tax Credit – 3% portion only recorded in FERC Account 255 (DGUADIT) directly associated with the Designated Generating Unit if known; otherwise, an allocation of the plant-related balances in FERC Accounts 190, 281, 282 and 283, as reduced by amounts not generally and properly includable for FERC cost of service purposes, including, but not limited to, SFAS 109 ADIT

amounts and ADIT amounts arising from retail ratemaking decisions, and Accumulated Deferred Investment Tax Credit – 3% portion only recorded in FERC Account 255 based on the proportion of gross Plant in Service for the Designated Generating Unit (DGUPLT), where DGUPLT is the sum of the investment pursuant to Section 30.04 (a) above plus the calculated General and Intangible plant pursuant to Sections 30.04 (f) and (h) below, to the Company's total gross Plant in Service (PLT), where PLT is the sum of Production, Transmission, Distribution, General and Intangible Plant in Service,

- (f) Plus an allocation of General Plant recorded in FERC Plant Accounts 389 through 398 (GPLT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding Administrative and General ("A&G") Labor (LXAG),
- (g) Less an allocation of Accumulated Provision for Depreciation (consistent with the accounting relating to SFAS 143 approved by the retail regulator having jurisdiction over the Designated Generating Unit, unless the FERC determines otherwise) associated with item (f) above as recorded in FERC Account 108 (GDR) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),
- (h) Plus an allocation of Miscellaneous Intangible Plant recorded in FERC Plant Account 303 (IPLT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),
- (i) Less an allocation of Accumulated Provision for Amortization associated with item (h) above recorded in FERC Account 111 (IAA) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),
- (j) Plus an allocation of Materials & Supplies and Stores Expense Undistributed recorded in FERC Accounts 154 and 163, respectively, (MS) based on the

- proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company's total Plant in Service (PLT), and
- (k) Plus an allocation of Prepayments recorded in FERC Account 165 (PP) based on the proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company's total Plant in Service (PLT).

The Investment in the Designated Generating Unit (Designated Generating Unit Rate Base) shall be based on the actual balances on the seller's books as of the end of the month immediately preceding the service month.

If the Designated Generating Unit is one of a multi-unit station, its costs shall include an allocation of the amounts in the above plant accounts, which are allocable to all the Generating Units in the station, such allocation to be in the ratio of the Capability of the Designated Generating Unit to the total Capability of all Generating Units installed in the station for the service month.

30.05 Expenses associated with Designated Generating Unit (OXP)

For the purpose of calculating the Monthly Capacity Charge under Section 30.06, expenses associated with Designated Generating Unit shall be the following:

$$\begin{aligned} \text{OXP} &= \text{Operating Expense} \\ \text{OXP} &= \text{DGUPOM} + [\text{SEOM} * (\text{DGUSEPLT} / \text{SEPLT})] + \text{DGUI} + \text{DGUI} + \\ &\quad \text{DGUPT} + \text{DGUAG} + [(\text{GD} + \text{OT} + \text{INDX}) * (\text{DGUL} / \text{LXAG})] + [\text{FT} \\ &\quad * (\text{DGUPLT} / \text{PLT})] \end{aligned}$$

- (a) The Designated Generating Unit Production Operation and Maintenance Expense ("O&M") Expense, included in FERC Accounts 500 through 554 excluding fuel in Accounts 501, 518 and 547 (DGUPOM),
- (b) Plus an allocation of O&M associated with Designated Generating Unit step-up transformers and related transmission investment recorded in FERC Accounts 562 and 570 (SEOM) based on the proportion of the Designated Generating Unit Step-up Transformer Plant recorded in Plant Account 353

(DGUSEPLT) to the Company's total Transformer Station Equipment Plant recorded in Plant Account 353 (SEPLT),

- (c) Plus any Depreciation Expense associated with the plant investment in Designated Generating Unit referred to in Section 30.04 items (a) and (b) (as recorded in Account 403) and Decommissioning Expense, as approved by Retail Regulators, directly assigned to the Designated Generating Unit, if applicable (DGUDE) unless the jurisdiction for determining the depreciation and/or decommissioning rate is vested in the FERC under otherwise applicable law,
- (d) Plus Property Insurance Expense recorded in FERC Account 924 directly assigned to the Designated Generating Unit (DGUI),
- (e) Plus Ad Valorem Taxes recorded in FERC Account 408 directly assigned to the Designated Generating Unit (DGUPT),

- (f) Plus A&G Expense (DGUAG) directly associated with a nuclear-fueled Designated Generating Unit recorded in FERC Accounts 920 through 935, excluding property insurance in Account 924; otherwise, an allocation of A&G Expense recorded in FERC Accounts 920 through 935 excluding property insurance in Account 924 based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding EOI and A&G labor,
- (g) Plus an allocation of General Plant Depreciation Expense recorded in FERC Account 403 (GDX) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),
- (h) Plus an allocation of Payroll Taxes recorded in FERC Account 408 (OT) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG),
- (i) Plus an allocation of Miscellaneous Intangible Plant Amortization Expense recorded in FERC Account 404 (INDX) based on the proportion of labor for the Designated Generating Unit (DGUL) to the Company's total Labor charged to O&M Expense excluding A&G Labor (LXAG), and
- (j) Plus an allocation of Corporate Franchise Taxes recorded in FERC Account 408 (FT) based on the proportion of Plant in Service for the Designated Generating Unit (DGUPLT) to the Company's total Plant in Service (PLT).

The expenses shall be based on transactions recorded on the seller's books for the service month.

If the Designated Generating Unit is one of a multi-unit station, expenses relating to the common plant shall be allocated to the Designated Generating Units in the station based on the ratio of the Capability of the Designated Generating Unit to the total Capability of all generating units installed in the station for the service month.

30.06 Determination of Monthly Capacity Charge

For the purpose of calculating the Monthly Capacity Charge (MC) per kW for billings under Capability Payment for each unit, the following formula shall be followed:

MC = Monthly Capacity Charge (\$/kW-Month)

$$MC = [DGURB * ((CM + F)/12) + OXP - ITC/(1-T)] / CP$$

Where:

DGURB = Designated Generating Unit Rate Base per Section 30.04

CM = The weighted average cost of capital consistent with the procedures used by each Operating Company to calculate its AFUDC rate, determined as follows:

$$CM = (DR * i) + (PR * p) + (ER * c), \text{ where}$$

DR = Ratio of Debt Capital and Preferred Stock with tax deductible dividends (QUIPS) at the last day of the month immediately preceding the current service month

PR = Ratio of Preferred Stock without tax deductible dividends at the last day of the month immediately preceding the current service month

ER = Ratio of Common Stock at the last day of the month immediately preceding the current service month

i = Average embedded cost of debt capital outstanding at the last day of the month immediately preceding the current service month

p = Average embedded cost of preferred stock outstanding at the last day of the month immediately preceding the current service month

c = Return on common equity at 11.0%

F = Federal and State Income Tax as determined from the following:

$$F = T / (1 - T) * (CM - DR * i)$$

Where:

- T = $f + s - fs$ when federal tax is not deductible in computing state tax,
and
T = $(f + s - 2fs) / (1 - fs)$ when federal tax is deductible in computing
state tax, and
f = Federal Income Tax Rate
s = State Income Tax Rate
- OXP = Operating Expense per Section 30.05
ITC = ITC Amortization recorded in FERC Account 411 directly associated with the
Designated Generating Unit if known; otherwise, an allocation of ITC
Amortization recorded in FERC Account 411 based on a gross plant-related
balance ratio
CP = Capability for the Designated Generating Unit as defined in Section 3.07 of this
Agreement for the service month

General Notes:

- (a) Labor ratios shall be determined based on the sum of the payroll expenses for the owner of the DGU, including those payroll expenses billed to it by EOI and ESI, for the service month.
- (b) Plant ratios shall be determined based on plant in service balances as of the end of the month immediately preceding the service month.

30.07 Adjustment for Tax Changes

The Capability Payment as determined above shall be adjusted to reflect the imposition of any applicable new taxes not included in the above formula or for any increase or decrease in taxes included as of the date of this Agreement.

30.08 Billings Procedure

Bills for services rendered under Section 30.06 shall be issued within 45 days following the end of the service month and shall be payable within 10 days of receipt. Five days after such bill is due, interest shall accrue on any balance due at the rate as determined in Section 35.19a(2)iii of the FERC Regulations. The billing provisions under Section 3.14 of this Agreement shall not apply to billings under Section 3.14 of this Agreement.

30.09 Designated Power Purchase

- (a) A "Designated Power Purchase" shall be any portion of a power purchase contract the sale and purchase of which is made pursuant to Section 30.01 hereof, which is mutually agreed upon by the purchaser and the seller. Any resale of a power purchase from the Grand Gulf nuclear unit pursuant to Section 30.09 shall be subject to the approval of the FERC and the regulatory agency of the purchasing company.
- (b) Any Company that makes a Designated Power Purchase of a portion of the Capability of the power purchase contract from which the sale and purchase is made shall be entitled to receive each hour, the same portion of the total Energy purchased pursuant to the Designated Power Purchase subject to review by the FERC.
- (c) Sales to one Company of power purchased by another Company shall be priced at the delivered cost of said purchase incurred by the selling Company as recorded in FERC Accounts 555 and 565, excluding all timing effects on such costs due to retail ratemaking decisions on a monthly basis, and shall be billed pursuant to Section 3.14 of this Agreement subject to review by the FERC.

SERVICE SCHEDULE No. 4

DISTRIBUTION OF REVENUE FROM SALES MADE FOR THE JOINT ACCOUNT OF ALL COMPANIES

Capitalized terms used in this Service Schedule No. 4 and not otherwise defined herein shall have the same meanings herein as ascribed thereto in Appendix A.

- 40.01 Purpose: The purpose of this Service Schedule is to provide a basis for the determination and distribution among the Companies of the net balance received from sales to others for the joint account of all the Companies.
- 40.02 Designation of Source Deemed to Supply Joint Account Sales: the highest-cost dispatchable Resource available in each hour will be deemed to supply Joint Account Sales. The Company that owns or controls a Resource deemed to have supplied a Joint Account Sale will be reimbursed on an hour-by-hour basis at the rate set forth by the sum of the Unit Fuel Cost and Unit Energy Adders determined in Service Schedule 1. The load associated with a Joint Account Sale will be removed from the System Load stack on an hour-by-hour basis, and Resources deemed to have supplied a Joint Account Sale will not be included in any of the energy stacks used in Service Schedules 1 and 2.
- 40.03 Revenue Deductions: from the gross revenue received for such sales there shall be deducted the cost of the sales determined by taking the sum of:
- a) Any direct tax imposed on the sale of Capacity or Energy or revenue derived there from.
 - b) Any appropriate adjustment for losses in the electric system of the Company providing the connection.
 - c) The cost of Energy determined under the provisions of Section 20.05(b)(iii) of Service Schedule ESI-2.
 - d) The Ownership Costs for the specific connecting facilities not equalized elsewhere. For this purpose, Ownership Costs shall be computed at the rate developed for the

connecting Company's Annual Ownership Cost under Service Schedule 6 on the facilities provided by the Company and approved by the CODA Management Committee.

40.04 Distribution of Net Balance: The net balance remaining after the deductions provided for in 40.02 shall be distributed among the Companies in proportion to the Responsibility Ratio for the immediately preceding Billing Period.

SERVICE SCHEDULE No. 5
PURCHASES OF SUPPLEMENTAL RESOURCES

Capitalized terms used in this Service Schedule No. 5 and not otherwise defined herein shall have the same meanings herein as ascribed thereto in Appendix A.

50.01 Purpose: The purpose of this Service Schedule is to provide for the purchase of sufficient Generation Resources by the System Dispatcher in the event that one or more Companies fail to provide sufficient Generation Resources to satisfy its Generation Resource Obligation.

50.02 Purchase of Supplemental Resources

- a) If a single Company fails to designate sufficient Generation Resources to satisfy the requirements of Section 3.05, the CODA Management Committee shall direct the Dispatcher to procure the deficient Resources from an unaffiliated third party. The full cost of the Resource shall be borne by the Company for which Resources are purchased. The capacity and Energy from the purchased Resource shall be assigned to the Company.
- b) If more than one Company fails to designate sufficient Generation Resources to satisfy the requirements of Section 3.05, the CODA Management Committee shall direct the Dispatcher to procure an amount of Supplemental Resources equal to the combined deficiencies of those Companies from an unaffiliated third party. The full cost of those Supplemental Resources shall be borne by the Companies for which Supplemental Resources are purchased. The capacity and Energy and associated costs for the Supplemental Resources shall be assigned to the deficient Companies on a pro-rata basis proportional to the amount of their deficiency.

SERVICE SCHEDULE No. 6
TRANSMISSION EQUALIZATION

Capitalized terms used in this Service Schedule No. 6 and not otherwise defined herein shall have the same meanings herein as ascribed thereto in Appendix A.

60.01 Purpose: The purpose of this Service Schedule is to provide the basis for equalizing among the Companies the ownership costs associated with Inter-Transmission Investment in such a manner that each Company will bear a portion of these costs proportional to its Responsibility Ratio.

60.02 Inter-Transmission Investment: A Company's Inter-Transmission Investment for the purpose of this schedule shall consist of:

- () All of the investment in transmission lines operated at 230 kV or higher voltage to the extent that such investment is not included in billings under other agreements.
- b) Investment in transmission substations with three or more lines operated at a voltage of 230 kV or higher to the extent that such investment is not included in billings under other agreements. Investment in such substations shall include facilities down to but not including the high side disconnecting device of the transformer, 50% of common facilities, and other facilities as approved by the Operating Committee. Common substation facilities are those facilities not directly associated with any of the major power supplying voltages of the substation. They include but are not limited to land, roadway, lighting, control house, fill, fencing, supervisory equipment, etc.
- c) All lines 230 kV and higher from the owning Company's last substation to the connecting point of another Company's substation or other transmission owner not a Party to this Agreement not included in (a), or not included in billings under other agreements
- d) Any investment made to qualify a Resource for network service under the Entergy OATT shall not be included in (a), (b), or in any billings under other Service Schedules of this Agreement.

The investment in a generating unit step-up transformer and associated switchgear, necessary to connect the generating unit to the lines or all buses, shall not be included in subsection (b).

In determining the investments above referred to under subsections (a) and (c), only those transmission line costs includable in Accounts 350, 352, 354, 355, 356, 357, 358 and 359 of the Federal Energy Regulatory Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

The investments above referred to under subsection (b) are amounts includable in the accounts listed in the preceding paragraph plus Account 353.

The investment in new transmission facilities included under this Service Schedule shall be added to a Company's Inter-Transmission Investment on the first day of the month following the "in service" date of the facilities. Each Company's Inter-Transmission Investment shall be revised as of the end of each month to adjust for any additions or retirements.

60.03 Company Net Inter-Transmission Investment - Company Net Inter-Transmission Investment shall be the sum of the Company Inter-Transmission Investments reduced for the Accumulated Provision for Depreciation and Deferred Taxes as adjusted at each December 31.

60.04 Transmission Responsibility - A Company's Transmission Responsibility shall be the sum of the System Net Inter-Transmission Investments multiplied by that Company's Responsibility Ratio.

60.05 Transmission Equalization Payments - Each Company shall pay or receive each month, as appropriate, an amount in dollars determined by the following formula:

$$\text{Dollars (\$)} = 1/12 (\text{TR} - \text{TI}) (\text{AOC})$$

where:

TR = The Company's Transmission Responsibility as defined in Section 60.04

TI = The Company's Net Inter-Transmission Investment as defined in Section 60.03

AOC = System Average Annual Ownership Cost

60.06 Development of Company's Annual Ownership Cost - (AOC_C) - The Annual Ownership Cost, expressed as a decimal, shall be determined as follows:

$$AOC_C = (CM + F) + \frac{D + I + PT + FT + OM}{K}$$

where:

CM = the weighted average cost of capital determined as follows:

$$CM = (DR \times i) + (PR \times p) + (ER \times c)$$

DR = Ratio of Debt Capital at Dec. 31 of the previous year

PR = Ratio of Preferred Stock at Dec. 31 of the previous year

ER = Ratio of Common Stock at Dec. 31 of the previous year

i = Average embedded cost of debt capital outstanding at Dec. 31 of the previous year

p = Average embedded cost of preferred stock outstanding at Dec. 31 of the previous year

c = Return on common equity at 11.0%

F = Federal and State Income Taxes as determined from the formulas:

$$F = \frac{T}{(1 - T)} \times [CM - DR \times i]$$

T = f + s - fs when federal tax is not deductible in computing state tax, and

$$T = \frac{f + s - 2fs}{1 - fs} \text{ when federal tax is deductible in computing state tax, and}$$

f = Federal Income Tax Rate

s = State Income Tax Rate weighted on prior year jurisdictional revenues if two or more state jurisdictions are served

K = The ratio of a Company's Net Inter-Transmission Investment and Inter-Transmission Investment (i.e., Section 60.03 ÷ Section 60.02)

D = Book depreciation as used by each Company expressed as a decimal of Inter-Transmission Investment (Section 60.02).

- I = Annual insurance cost expressed as a decimal of Inter-Transmission Investment (Section 60.02).
- PT = Average ad valorem taxes based on preceding year's tax rates and assessments for the Inter-Transmission Investment expressed as a decimal of Inter-Transmission Investment (Section 60.02).
- FT = Corporate Franchise Tax based on preceding year's Inter-Transmission Investment expressed as a decimal of Inter-Transmission Investment (Section 60.02).
- OM = Operating and maintenance expenses plus the applicable general and administrative expenses expressed as a decimal of Inter-Transmission Investment (Section 60.02). These combined expenses will be determined annually by taking the applicable accounts for each Company, related to their total transmission investment, together with the applicable general and administrative expenses and proportioned to the direct labor expenses.

Direct - Accounts 560, 561, 562, 563, 564, 565, 566, 567, 568, 569, 570, 571, 572 and 573

Allocable - Accounts 920, 921, 922, 923, 924, 925, 926, 927, 928, 929, 930, 931 and 932

60.07 Development of System Average Annual Ownership Cost

The System Average Annual Ownership Cost to be applied to this Service Schedule shall be developed from the following formula:

$$AOC = \frac{(A \times AOC_A) + (G \times AOC_G) + (L \times AOC_L) + (M \times AOC_M) + (N \times AOC_N) + (T \times AOC_T)}{A + G + L + M + N + T}$$

where:

AOC = System Average Annual Ownership Cost

A = EAI Net Inter-Transmission Investment

G = EGSL Net Inter-Transmission Investment

L = ELL Net Inter-Transmission Investment

M = EMI Net Inter-Transmission Investment
N = ENOI Net Inter-Transmission Investment
T = ETI Net Inter-Transmission Investment
 AOC_A = EAI - Annual Ownership Cost
 AOC_G = EGSL - Annual Ownership Cost
 AOC_L = ELL - Annual Ownership Cost
 AOC_M = EMI - Annual Ownership Cost
 AOC_N = ENOI - Annual Ownership Cost
 AOC_T = ETI - Annual Ownership Cost

60.08 Adjustment for Tax Changes

The Transmission Equalization Payment as determined in Section 60.05 shall be adjusted to reflect the imposition of any applicable new taxes not included in the above formula, or for any increase or decrease in taxes included as of the date of this Agreement.

60.09 Billing Procedure

The billing parameters will be in effect from June 1 to the succeeding May 31, based on the preceding year's results.

Appendix A: Defined Terms

1. "Agent" shall mean Services, which shall act as agent for one or more of the Companies in all matters delegated by the Operating Companies.
2. "Agreement" shall mean this Commitment, Operations, and Dispatch Agreement (hereinafter sometimes referred to as the "CODA"), together with all attachments and Service Schedules and any amendments or supplements made hereafter.
3. "Billing Period" shall be determined by the CODA Management Committee
4. "Capability" shall mean the net output (in MW) of a generating unit or power purchase agreement that has been placed under the control of the System Dispatcher to supply the Total System Load. Capability shall be determined under conditions specified by the CODA Management Committee, and the amount of each Company's Capability shall be reviewed and approved by the CODA Management Committee no less than annually.
5. "Capability Responsibility" of a Company shall mean the Generation Resource Obligation multiplied by the Responsibility Ratio for that Company.
6. "Capacity" shall refer to the amount of power that can be supplied by a generating unit or station, or through a purchased power agreement, or the amount of power needed for some specified period of time by a designated set of an Operating Company's customers.
7. "CODA Management Committee" shall mean the administrative organization created under this Agreement to administer its provisions.
8. "Company" or "Companies" shall have the meaning set forth in the Recitals of this Agreement.
9. "Company Total Load" shall mean the total amount of energy, expressed in MWh per hour or MW, that a Company has delivered or plans to deliver to its own customers, including retail and unaffiliated wholesale customers.
10. "Company Total Load Responsibility" shall mean the ratio of a Company Total Load to the System Total Load at the time of the peak System Total Load for the Billing Period.

11. "Commitment Period" is a forward-looking one week period running from Monday to Sunday, unless otherwise defined by the CODA Management Committee.
12. "Controllable Demand Side Agreement" shall mean a contract, tariff or agreement between a Company and one of its customers that provides the Company, or its agent, with the right to reduce the load of a customer by a defined amount on at least 20 Days in each calendar month with no more than 24-hours' notice. The System Dispatcher, under the direction of the CODA Management Committee, shall review each Controllable Demand Side Agreement and confirm that it meets the established requirements. Any reduction in load achieved as a result of Controllable Demand Side Agreement shall be treated as Energy for purposes of the Economy Energy Exchange. A Controllable Demand Side Agreement shall not be treated as Flexible Capability.
13. "Daily Operation Plan" shall mean a plan that identifies the set of Resources that will be used to satisfy the combined loads of the Companies during a Day, including a reserve requirement.
14. "Day" shall mean a continuous 24-hour period beginning at midnight Central Pacific Time, or such other time as may be agreed upon by the CODA Management Committee.
15. "Deployed Flex" shall mean the sum of the Flexible Capability provided by the Generation Resources included in the Daily Operation Plan.
16. "Demand Side Management ("DSM") Resources" shall mean Company programs that increase energy efficiency or the management of demand. The term includes load management techniques.
17. "EAI" shall have the meaning set forth in the Preamble of this Agreement.
18. "Economy Energy" shall mean the Energy exchanged among those Companies that are either Long or Short via the provisions of Service Schedule ESI-2.
19. "Economy Energy Pool" shall mean the total amount of MWh and costs exchanged among the Companies in each hour via the provisions of Service Schedule ESI-2. The Economy Energy Pool will equal the sum of all of the Long Companies' MWh of
20. "Effective Date" shall have the meaning set forth in Section 1.01.
21. "Effective Time" shall have the meaning set forth in Section 1.01.

22. "EGSL" shall have the meaning set forth in the Preamble of this Agreement.
23. "Eligible Generation Resource" shall mean a Generation Resource that has been designated by an Operating Company pursuant to Section 3.06 and Qualified by the CODA Management Committee pursuant to Section 3.07.
24. "ELL" shall have the meaning set forth in the Preamble of this Agreement.
25. "EMI" shall have the meaning set forth in the Preamble of this Agreement.
26. "Energy" shall mean work and shall be expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).
27. "Energy Imbalance Sales" shall mean sales of energy made pursuant to the Energy Imbalance Provisions of the Entergy OATT.
28. "Energy Stack" shall mean the set of a Company's hourly energy sources used, in conjunction with such Company's Load Stack, for the purpose of identifying whether such Company is Long or Short on Energy.
29. "ENOI" shall have the meaning set forth in the Preamble of this Agreement.
30. "Entergy Open Access Transmission Tariff" or "OATT" shall mean the FERC-approved tariff under which the Entergy Operating Companies provide transmission service.
31. "ETI" shall have the meaning set forth in the Preamble of this Agreement.
32. "FERC" shall have the meaning set forth in Section 1.01.
33. "Flexible Capability" shall mean that portion of a Generation Resource, expressed in MW, that can increase or decrease MWh production upon direction from the System Dispatcher within a two-hour period.
34. "Flexible Energy" shall mean the Energy that is produced when a Generation Resource that is providing Flexible Capability is operating at its Minimum Operating Level.
35. "Flexible Energy Exchange" shall mean the mechanism used to allocate the cost and Energy associated with the provision of Flexible Capability.
36. "Generating Unit" shall mean an electric generator, together with its prime mover, and all auxiliary and appurtenant devices and equipment designed to be operated as a unit for the production of Energy, or as otherwise determined by the CODA Management Committee.

37. "Generation Resource" shall mean owned or co-owned Generating Units, contracts that provide access to such Generating Units, or Controllable Demand Side Agreements.
38. "Generation Resource Obligation" shall mean the amount of Capability that the CODA Management Committee has determined to be required for future periods.
39. "Generator Imbalance Sales" shall mean sales made pursuant to the Generator Imbalance Agreement requirements of the Entergy Open Access Transmission Tariff.
40. "Hourly Avoided Cost" shall mean the hourly avoided energy cost rate, expressed in \$/MWh, that is calculated to comply with the requirements of the Public Utilities Regulatory Policies Act of 1978 for payments to Qualifying Facilities for hourly energy. To the extent that the Companies' retail regulators direct that different hourly avoided cost rates be calculated for different Companies, the CODA Management Committee shall determine which hourly avoided cost should be used.
41. "Hourly QF Put" shall mean the total Energy delivered to the Companies during a clock hour by Qualifying Facilities operating pursuant to the provisions of Public Utilities Regulatory Policy Act of 1978.
42. "Joint Account Purchases" shall mean purchases of electric capacity or Energy made by the System Dispatcher for the benefit of all Companies.
43. "Joint Account Sales" shall mean sales of electric capacity or Energy made by the System Dispatcher from the Resources of the Companies for the benefit of all Companies.
44. "kW" means kilowatts.
45. "kWh" means kilowatt hours.
46. "Load" shall mean the amount of energy, expressed in MWh per hour or MW, that a Company has delivered or plans to deliver to its own customers, including retail and unaffiliated wholesale customers.
47. "Load Stack" shall mean a mathematical representation of a Company's Total Load and is used, in conjunction with a Company's Energy Stack, for the purpose of identifying whether a Company is Long or Short on Energy.

48. "Long" shall mean a situation when a Company has more Resources than necessary to satisfy its Resource obligation, or a situation in which a Company's Energy production exceeds its energy requirements.
49. "Maximum Operating Level" shall mean the highest output level at which an Eligible Generation Resource may be operated as specified by the Company that owns that Eligible Generation Resource and approved by the CODA Management Committee.
50. "Minimum Operating Level" shall mean the lowest output level at which an Eligible Generation Resource may be operated as specified by the Company that owns that Eligible Generation Resource and approved by the CODA Management Committee.
51. "MW" means megawatts.
52. "MWh" means megawatt hours.
53. "Partial Resource" shall mean that an Eligible Generation Resource is a portion of an electric generation facility or purchased power contract.
54. "Party" or "Parties" shall have the meaning set forth in the Preamble of this Agreement.
55. "Planning Reserve Margin" shall mean the percentage by which System Resources should exceed expected Total Electric System Load in future years.
56. "Power" shall mean the rate of doing work and shall be expressed in kilowatts (kW), megawatts (MW), or gigawatts (GW).
57. "Production Cost Equalization Mechanism" shall mean a mechanism that compares the production cost of a Company to some average aggregated production cost and calculates a payment or receipt for the various Companies based on some deviation from the average cost.
58. "Qualified Resource" shall mean a Resource that has been designated by an Operating Company pursuant to Section 3.06 and Qualified by the CODA Management Committee pursuant to Section 3.07
59. "Qualifying Facilities" shall mean a cogeneration facility that qualifies under Subpart B of Part 292 of the Regulations of the FERC, 18 C.F.R. § 292.201, et seq., as amended, or any successor provisions issued pursuant to Section 3(18)(B) of the Federal Power Act
60. "Requirements" shall mean the total amount of energy that a Company uses to meet all of its sales obligations, including but not limited to retail customers, interruptible

- retail customers, wholesale customers purchasing from a Company under a long-term full requirements contract, and wholesale customers purchasing short-term as-available power, over some defined period of time.
61. "Resource Flex" shall mean the amount of Flexible Capability provided by a Generation Resource and is measured as the difference between the Minimum Operating Level and Maximum Operating Level of the Generation Resource less any portion of that range at which the Generation Resource cannot be operated at a stable level.
 62. "Resources" shall mean sources that can be used to meet customer requirements, including Generation Units, Purchases and DSM Resources.
 63. "Responsibility Ratio" of a Company shall mean the ratio obtained by dividing the Company's Total Load during the clock hour in which the System Total Load achieves its highest level during a Billing Period, divided by the System Total Load during the same clock hour.
 64. "Short" shall mean a situation when a Company has insufficient Resources to satisfy a Resource obligation, or a situation in which a Company's Energy production is less than its Energy requirements.
 65. "System" shall mean the interconnected coordinated generation and bulk power transmission facilities of the Companies.
 66. "System Agreement" shall have the meaning set forth in the Recitals of this Agreement.
 67. "System Capability" shall mean the arithmetical sum in MW of the individual Company Capabilities.
 68. "System Dispatcher" shall mean the entity that prepares the unit commitment schedule and conducts the security constrained economic dispatch of the Companies' Qualified Resources, which function currently is performed by the System Planning and Operations Department within Services.
 69. "System Resources" shall mean the sum of the Eligible Resources of the Companies.
 70. "System Total Load" shall mean the coincident sum of the Total Company Loads.
 71. "Total Joint Account Load" shall mean the sum of Total Joint Account Sales, Generator Imbalance Sales, and Energy Imbalance Sales, and may be calculated for individual Companies or for the System as a whole.

72. "Total Joint Account Sales" shall mean the sum of all Joint Account Sales in an hour, and may be calculated for the individual Companies or the System as a whole.
73. "Total Load" shall mean, for a Company, the sum of its obligations to provide energy in each hour and, for the System, the sum of the Total Loads of the Companies.
74. "Unit Fuel Cost" shall mean the estimated hourly cost of fuel delivered to a plant, expressed in \$/mmBtu, including commodity costs, transportation costs, measurement or testing costs, taxes, emission allowance costs, and any other cost adder deemed by the CODA Management Committee to be appropriate.

IN WITNESS WHEREOF each of the Parties has caused these presents to be signed in its name and on its behalf by its President, attested by its Secretary, both being duly authorized.

INSERT APPROPRIATE SIGNATURE BLOCK