Discussions on Ancillary Services

ERC CASE NO. 2002-253

TransCo

CORPORATE PLANNING AND DEVELOPMENT GROUP
NATIONAL TRANSMISSION CORPORATION

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1. Introduction

The Philippine Grid Code defines Ancillary Service as “support services such as Frequency Regulating and Contingency Reserves, Reactive Power support, and Black Start capability which are necessary to support the transmission capacity and Energy that are essential in maintaining Power Quality and the Reliability and Security of the Grid.” Prior to the enactment of the Electric Power Industry Reform Act of 2001, the National Power Corporation (NPC), as a vertically integrated public utility, planned for and deployed generation, transmission and system operations resources to produce ancillary services as part of its normal operations.

Historically, no one other than NPC needed to understand the definitions and applications of these ancillary services. In 1997 however, ancillary services first came into the industry’s consciousness when the Energy Regulatory Board (ERB) approved NPC’s Open Access Transmission Tariff (OATT) and the Tariff for Ancillary Services (TAS). These two services, power delivery service and ancillary services, are the transmission services that NPC provides to privately owned generators under its Open Access Transmission Service of 1997 (1997 OATS). The 1997 OATS was in support of Executive Order 215 allowing private sector’s participation in electricity generation. It is under the terms and conditions of the 1997 OATS that TransCo currently implements open access pending the Energy Regulatory Commission’ (ERC’s) approval of the 2003 OATS Rules (ERC Case 2002-253).

This paper presents the basic concepts of ancillary services to demonstrate their importance for the viability of electric industry structure and operation. This paper is also in compliance with the ERC’s order dated March 24, 2003 under ERC Case 2002-253 directing TransCo to submit:

(a) detailed description of each ancillary service including their respective functionality and operational characteristics;

(b) calculations and system analysis supporting the need for the level of capacity for each proposed ancillary services; and

(c) demonstration on actual system data that the level of capacity as proposed is available and can actually perform the functionality of each ancillary service at all times, including (i) actual outage scenario(s) wherein the total level of spinning reserves and back-up service capacity would be used in concert one another; and (ii) data showing that both the spinning reserves and back-up capacity are fully dispatchable.

2. Definitions

2.1 FERC Definitions

The United States' Federal Energy Regulatory Commission (FERC) defines ancillary services as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." This statement recognizes the importance of ancillary services for bulk-power reliability and to support commercial transactions.

FERC has named six ancillary services:

1. Scheduling, System Control, and Dispatch Service;
2. Reactive Supply and Voltage Control from Generation Sources Service;
3. Regulation and Frequency Response Service;
4. Energy Imbalance Service;
5. Operating Reserve - Spinning Reserve Service; and
6. Operating Reserve – Supplemental Reserve Service.

FERC specified the first two services, system control and voltage control, as services that transmission customers are required to obtain from the transmission provider. FERC determined that the system operator could only provide these services. For the other four services, however, FERC allows transmission customers to obtain the service in any one of three ways: from the transmission provider, from another source, or by self-provision.

FERC also discussed other ancillary services, namely, real-power loss replacement, dynamic scheduling, backup supply and black start capability. FERC determined that these services could be provided competitively, were relatively inexpensive, or were very highly location specific and therefore did not require transmission providers to unbundled and offer them as separate services.

2.2 NPC Definitions

On August 8, 1996, NPC filed with the ERB an application for the approval of the OATS tariffs and tariffs for ancillary services that would be applicable to private sector generation facilities. Subsequent collaborative discussions resulted to the ERB approval of the Stipulation and Agreement, which included among others, the definition and discussions on ancillary services, attached hereto as Appendix A. These services, whose definitions are primarily based on the FERC, are as follows:

1. System Operation and Planning
2. Load Following and Frequency Regulation Service
3. Reactive Supply and Voltage Control Service
4. Spinning Reserve Service
5. Security Redispatch
6. Schedule Imbalance Service
7. Loss Compensation Service
8. Start-up Service
9. Maintenance Service
10. Back-Up Service

During that time when the OATS was drafted, NPC was a vertically integrated public utility that owned and controlled both generation and transmission facilities. For this reason, NPC had been providing the ancillary services requirements of the grid. Noticeably, the definitions and discussions found in Appendix B made mentions of the transmission provider (NPC) owning and controlling generating resources.

These circumstances changed with the enactment of Electric Power Industry Reform Act of 2001, which created TransCo to take over the transmission functions of NPC. Since TransCo no longer owns nor controls generation, the ancillary services, as defined under the 1997 OATS, have to be taken on a different light.

Although the provisions of energy imbalance and loss compensation services are included in the list, they can be later integrated into the Wholesale Electricity Spot Market (WESM). Scheduling, system control and dispatch service are not necessarily ancillary service as the system operator can only provide these functions. In fact, the charges for these services may be bundled with the basic transmission tariff. Inasmuch as the need for reactive supply is localized in nature, discussions on this service shall be limited. Other services such as black start service, startup service, and maintenance service can be considered fairly uncontroversial, and shall not require comprehensive discussions. Thus, this paper shall focus its discussions on load following/frequency regulation and operating reserves (spinning reserve and backup service).

Ancillary services are a “common good”; everybody using the transmission system shares them. These services are basically the old system services that NPC, as a vertically integrated utility, wanted to charge under the 1997 OATS. These services entail additional costs incurred in wheeling electricity through NPC’s grid. As the industry gears toward a wholesale market, there is a need to take a second look at how TransCo would treat each ancillary service. It is important to revisit the industry’s definition of, procurement of, and payment for ancillary services. The procedures traditionally used by NPC may not serve the needs of an increasingly competitive market.

3. Functionality and Operational Characteristics

3.1 Load Following and Frequency Regulation Service

Regulation involves the use of generators and fuel to follow minute-to-minute fluctuations in system load. The frequent change in output at a generator that provides regulation increases costs in the following ways:

1. These output changes raise heat rates, which increases fuel costs.
2. The frequent changes in output and in direction increase operation and maintenance (O&M) costs because of the increased wear and tear of the unit.
3. This increase wear and tear reduces the operating life of the unit.
4. As with voltage control, the need to provide regulating headroom imposes an opportunity cost on that generator because it cannot sell the output it could produce. This opportunity cost may cause a change in the marginal unit and therefore the market price of energy, possibly a hidden cost of regulation.
5. Similarly, the need to provide "foot room" may require a unit to produce more energy than it would otherwise, incurring an uneconomical fuel cost and imposing an opportunity cost on other lower-cost unit.
6. Automatic control of the unit output from a remote location requires communication and control equipment, imposing additional capital cost.

Load following is the interhour equivalent of (intrahour) regulation. The amount of capacity needed for load following is up to ten times as much as needed for regulation but the required ramp rate is much slower. Utilities today maintain extra generating capacity online to respond to the rapid fluctuations in customer load. Typically, utilities provide 1 to 3% of capacity for this purpose. All customers pay for this capacity.

Together, regulation and load following address the temporal variations in load (and generation that does not accurately follow control signals). Generating units must be deployed to match the fluctuations in load (and other generators). The key distinction between load following and regulation is the time period over which these fluctuations occur. Regulation responds to rapid load fluctuations (on the order of one minute) and load following responds to slower changes (on the order of five to thirty minutes).

The primary cost of these services is the opportunity cost associated with the need to commit some of the unit's capacity to follow a particular load shape. This commitment reduces the opportunity of the generator to sell energy. In addition, load following may involve delivery of energy as well as capacity. This energy cost will be associated with fuel and variable O&M. As with regulation, the need to withhold capacity from the energy market to provide load following can impact the price of energy as well.

3.2 Operating Reserves

Operating reserves are the front lines in the defense of bulk-power systems against major generation and transmission outages. Operating reserves are provided by generating units that can respond to the sudden and unexpected loss of a supply resource (such as a major generating unit or a large transmission line) quickly enough to maintain system reliability and restore the system to generation/load balance and the system frequency. Operating reserves are divided into two components, spinning reserve and supplemental reserve.

3.2.1 Operating Reserve - Spinning Reserve

Spinning reserve is the use of generating equipment that is online and synchronized to the grid that can begin to increase output immediately in response to changes in system frequency and that can be fully available within ten minutes to correct for generation/load imbalances caused by generation or transmission outages. Almost all generators that supply spinning reserve are equipped with governors and automatic generation control (AGC). In principle, loads that are frequency responsive or that are under the control of the system operator could help provide this service.

Two factors affect the overall cost of energy. First, some of the units used to provide energy under least-cost dispatch are backed off to provide spinning reserve, requiring the use of more expensive generating units to provide energy. Second, the units that provide spinning reserve are operated with their valves partially closed to permit the valves to open fully when frequency drops and the governor calls for more turbine-generator output; operating with valves partially, rather than fully, open degrades the unit's heat rate and increases its operating costs. The cost of the unit's governor and control system, which responds automatically to frequency deviations, can be attributed in part to spinning reserve (with the remainder assigned to regulation). Similarly, part of the cost of AGC equipment can be associated with spinning reserve.

3.2.2 Operating Reserve – Supplemental Reserve

Supplemental reserve (backup supply) is the use of generating equipment and interruptible load that can be fully available within ten minutes to correct for generation/load imbalances caused by generation or transmission outages. Supplemental reserve differs from spinning reserve in that supplemental reserve need not begin responding to an outage immediately.

Supplemental reserve refers to generation that is available under contract to provide energy when the generator associated with a particular transaction fails. In addition to incurring the same costs as the primary supplier when the service is actually delivered, the supplier incurs opportunity costs associated with being ready to supply this service. These costs are not as severe as those incurred by generators supplying operating reserves because the advance notice for provision of backup supply is typically thirty to sixty minutes. Therefore, the generator supplying this service is free to engage in short-term transactions (e.g., sell non-firm energy).

3.2.3 Automatic Generation Control (AGC)

AGC is a means for secondary frequency control utilizing the energy management system/supervisory control and data acquisition system that allows the nominal frequency top be maintained at the nominal value with due consideration to system generation cost and security. On the other hand, the free governor operation or primary frequency response is a means of maintaining the system frequency at the nominal value (60 Hz) by the automatic fast adjustment of the output of generators (corresponding to changes in load or loss of generation) through the speed governing system.

3.2.4 TransCo's Recommended Operating Limits

Except for hydro plants (which normally have a zero dead band), the frequency dead band of generating plants on free governor operation mode shall be set preferably: (i) less than +/- 0.15 Hz for units providing frequency regulation; and (ii) –0.15 to –0.3 Hz for units providing spinning reserve. The governor droop setting, depending on the type of generating plant, shall be 5% or less with a maximum response time of 5 seconds. The maximum response time for the change in power output is 25 seconds and should be sustainable for at least 30 minutes. (Governor is a turbine controller that enables the unit to adjust the valve opening according to the demand of the system.)

3.2.5 Application of Operating Reserves

The following explains how an electric system is intended to operate when a major generating unit suddenly trips offline.

Prior to the outage, system frequency is very close to its 60-Hz reference value. Generally, within a second after the outage occurs, frequency drops. In the Luzon Grid, a loss of 500 MW during peak hour (about 8 % of the peak load), would dip the frequency to 58.8 Hz, and settle at 59.4 Hz after 30 seconds. The frequency decline is arrested primarily because many electrical loads (e.g., motors) are frequency responsive; that is, their demand varies with system frequency.

If the contingency is sufficiently large, underfrequency relays will automatically interrupt certain loads. Currently, TransCo's System Operations (SO) is implementing a corrective measure called the automatic load dropping (ALD). ALD is the immediate cutback of load to maintain generation-load balance aimed at stabilizing system frequency. ALD is set to commence at frequency level of 59.1 Hz, with a decrement of 0.1 Hz, down to 57.7 Hz. SO has designed a scheme wherein customers are grouped together, each group with corresponding frequency range that responds to ALD aimed at arresting the drop in frequency during outages.

Once the frequency decline exceeds the deadband of the generator governors, the governors at those generators so equipped sense the frequency decline and open valves on the steam turbines, which rapidly increases generator output (primary response). After a few more seconds, generator output declines slightly because the higher steam flow through the turbine is not matched by the steam flow from the boiler to the turbine. At this point, the operating reserves, in response to AGC signals from the control center, kick in (secondary response). More fuel is added to the boiler, leading to a faster rate of steam production, which leads to a higher power output.

3.2.6 ALD or Load Shedding

Load shedding or automatic load dropping is the process of deliberately disconnecting pre-selected loads from the power system in response to a loss of power input to the system in order to maintain the nominal value of the frequency. It is used as a last resort after all other less extreme emergency operating procedures has been attempted. The different load shedding schedule that TransCo's System Operations implement are shown in Appendix B.
ALD through the use of undefrequency detectors is a universally accepted method of preventing excessive frequency drops and possible system collapse or cascade tripping of power plants following a sudden loss of large power input to the system. The underfrequency relays (UFRs) monitor system frequency at the high voltage level by connecting the relays to the secondary windings or potential transformers in the substation.

3.3 Reactive Supply and Voltage Control Service

On an alternating-current (AC) power system, voltage is controlled by managing production and absorption of reactive power. There are three reasons why it is necessary to manage reactive power and control voltage. First, both customer and power-system equipment are designed to operate within range of voltages, usually within +/- 5% of the nominal voltage. At low voltages, many types of equipment perform poorly; light bulbs provide less illumination, induction motors can overheat and be damaged, and some electronic equipment will not operate at all. High voltages can damage equipment and shorten their lifetimes.

Second, reactive power consumes transmission and generation resources. To maximize the amount of real power that can be transferred across a congested transmission interface, reactive power flows must be minimized. Similarly, reactive power production can limit a generator's real power capability.

Third, moving reactive power on the transmission system incurs real power losses. Both capacity and energy must be supplied to replace these losses.

Voltage control involves the installation and use of equipment at generating units and throughout the transmission grid to maintain voltages within required limits. The costs of such transmission-system equipment (including capacitors, tap-changing transformers, static VAR compensators) can be readily determined and assigned to this service. However, generation-related costs of voltage control, which should be a separate service, are difficult to isolate. These costs are primarily associated with the capital costs of equipment, especially exciters and automatic voltage regulators. These pieces of equipment are required for the production of real power as well as reactive power, which complicates the assignment of costs to each service. In principle, one could determine the cost of a generating unit if it had zero reactive power capability. The incremental cost associated with the ability to produce and absorb reactive power could then be assigned to voltage control. Additional capital costs are associated with the increased capacity required for step-up transformer (e.g., for a 1000-MW generating station with a rated power factor of 90 percent, the transformer rating must be increased to 1100 MVA).

In addition to the capital cost, provision of reactive support may involve an opportunity cost. This opportunity cost refers to the tradeoff between a generator's ability to produce real vs. reactive power. At power factors close to 1, reactive power production results in almost no loss in real power production capability. But as the power factor drops, the real power penalty increases. If a generator would otherwise be operating at or near its peak real power output, a requirement to increase VAR output would necessitate a reduction in real power output. The loss of revenue from this foregone energy sales is an opportunity cost.

3.4 Black Start Capability

The power system must be prepared for the rare occasions when all or a major portion of the system is forced out of service. This might be the result of a particularly severe disturbance resulting in the loss of stability and the need for many generators to shut down. If this occurs, the system must be able to be restored to normal operations as quickly as possible. This is called system black start capability.

System black start capability is the ability of a grid to recover from a major system outage. The key requirement for recovery is generating units that can go from a shutdown condition to an operating condition without support from the electrical system. This capability is essential during large-scale blackouts and islanding because such units can start themselves and then produce power that can be used to energize the grid and provide power to start other generating units. This service is somewhat location dependent, which may limit the ability of third parties to provide the service.

3.4.1 Components of System Black Start

The coordination problem of re-energizing the grid is a complex process. Generators, black start capable or not, have minimum and maximum load limits (MW) and maximum ramp rates (MW/minute). As the first generators come back online, the system operator must provide sufficient load to keep the units stable (above the minimum load limits) but not exceed the generating capability, ramping limits, or voltage-control capability. This is a problem of balancing generation and load when both, along with the system configuration, are changing rapidly. Real power load is obtained by re-energizing groups of customers. Timing is critical because of the overall need to restore the system rapidly but also because the non-black start generators are each coming online as loads because of their auxiliary equipment, increasing that load as they prepare to restart generation, and then requiring load themselves when they synchronize to the grid and begin delivering power. The longer it takes to restore offsite power to non-black start generators, the longer it can take for these units to return to service. Such delays can occur because conditions at the non-black start generators deteriorate the longer they are without power to operate their auxiliaries.

The Transmission system itself presents a dynamic reactive load. The transmission system is highly capacitive when it is not loaded. Voltages can easily become excessive. Generators and reactors are used to hold voltages down. Unfortunately, generators are less stable when they are absorbing large amounts of reactive power than when they are producing reactive power. The system operator must be aware of each unit's reactive capabilities and the load that will be imposed as each transmission system is energized.

3.5 System Operations

Similar to the aviation industry where air-traffic controllers are needed to manage the landings, take-offs, and movements of airplanes for safety and commerce, the electricity industry requires system operator. The electrical system control functions encompass a range of activities that maintain bulk-power reliability support and ensure orderly commercial transactions.

3.5.1 System Operator Role

By definition, the system operator is the only entity that can provide the system control and scheduling service. However, almost by definition, the system operator cannot provide any of the other services. To the extent that the system operator is independent of he owners of generation and transmission, it will own no generating and perhaps no transmission assets. Thus, it will not be able to provide these ancillary services.

However, the system operator may need to control the provision of many of these services. The role of the system operator is crucial because it is much more cost effective to provide many of the services (e.g., regulation, voltage control, and operating reserves) for the aggregate load than each load separately.

With respect to system services, the system operator – and only the system operator – knows what the regulation requirements are for the system from second to second. Thus, although the generators that provide this service are neither owned nor operated by the system operator, their provision of the regulation service is controlled by the AGC signals that the system operator sends to each generating unit that is providing the service.

In a similar fashion, only the system operator, based on its knowledge of power flows and possible contingencies, can set the voltage schedules and reactive power reserves throughout the transmission grid. During emergency conditions, only the system operator can determine the appropriate voltages throughout the grid and therefore is the only entity that can direct generator reactive power operations. Therefore, voltage schedules and the resulting reactive power injection and absorption must be under the control of the system operator.

The same situations apply to the operating reserve services and black start capability. For these services, the system operator is the only entity with sufficient and timely information to decide how much of this service is required. In addition, system provision of the service, rather than customer provision, provides economies of scale. That is, fewer resources are required to provide a given level of service to an aggregation of loads than to the sum of the individual loads.

3.6 Energy Imbalance Service

Energy imbalance service refers to the use of generation to correct for hourly mismatches between actual and scheduled transactions between suppliers and their customers. Energy imbalance is unfortunately unavoidable because it is impossible to match generation to load.

Current definition of energy imbalance specifies a deadband of ±1.5%. If the deviation between actual and scheduled flows, measured over each one-hour period, is within this deadband, the transmission customer, subject to an agreement with TransCo, may return the imbalance "in kind" during a like period (on peak or off peak) within the billing period. This means that within this deadband, over- and under-generation can offset each other.

As argued earlier, energy imbalance should be integrated in the settlement mechanisms of the spot market. It will be likely be priced in P/KWh and charged on the basis of a transaction's net hourly imbalance and the current hourly spot-market price. Ultimately, the current complicated system of deadband and "in-kind" payment will likely disappear and be replaced by market-based systems.

3.7 Real Power Loss Replacement

Real power losses are the difference between generated real power and the real power delivered to customer. Moving power always result in losses because of the resistance of each element in the transmission and distribution system.

Currently, loss compensation is determined by attributing a loss factor determined to the 0.01%, to the output of a generator to determine the amount of capacity and energy deemed to have been delivered to the receiving party. The loss factor is also being applied on a per grid basis.

Loss replacement will also likely be priced in P/KWh and charged on the basis of the current hourly spot-market price with the amount of service computed hourly.

3.7.1 Loss Factor for the Different Grids

The loss factor is computed based on the system net generation, i.e., excluding plant station use, for all generating stations in the grid and the total energy delivered to all loads for a 24-month period. This period can be considered sufficient enough to ensure stability on the resulting loss factor. The loss factor for the different grids based on year 2000 data are as follows:

Luzon	2.98%
Visayas	3.67%
Mindanao	4.35%

3.8 Startup Service and Maintenance Service

A transmission customer has the option to arrange with other generators its startup service and maintenance service requirements. The provision of such service shall be coordinated with TransCo and shall be treated as a backup supply arrangement or under the market, based on the spot energy purchase.

4. Calculations and System Analysis

4.1 Regulation and Load Following

Electricity is a real-time product, with its production, transportation, and consumption occurring within a fraction of second. Electricity moves at nearly the speed of light and cannot be readily stored. For these reasons, bulk power systems must maintain a continuous and near-instantaneous balance between production and consumption. The system operator must adjust generation to meet load on a near-instantaneous basis. As the generation is separated from transmission and system control, defining the responsibilities to meet time-varying load requirements becomes very important.

Loads consist of three elements. The first element is the average load during the scheduling period. The second element is the trend during the hour and from hour to hour while the third element are the rapid fluctuations in load around the underlying trend.

The second and third elements are called load following and regulation. These two services plus energy imbalance service together ensure that, under normal operating conditions, system operator is able to continuously balance generation to load.

4.1.1 Level of Regulation and Load Following

The 2.8% level currently being used for load following and spinning reserve represents the historical largest load pick up in the grid within an hour expressed as a percentage of the peak system load for the year. This percentage was based on actual 1995 data and was part of the 1997 OATS Stipulation and Agreement approved by the ERB.

4.2 Operating Reserves

Operating reserve requirements could be based on either probabilistic or deterministic calculations. Ideally, utilities would conduct both types of analyses, testing the results against different sensitivities related to unit-specific forced outage rates, capacity costs, transmission constraints, and other factors. In general, however, these requirements are currently based primarily on the magnitude of the largest single contingency. The thinking behind this approach is that the system must be able to withstand such a contingency regardless of the probability of its occurrence. In other words, even if the largest generator has an excellent reliability record (e.g., less than one forced outage a year), the consequences of such an outage are so severe that the system must be protected against its occurrence.

4.2.1 Level of Contingency Reserve (Spinning Reserve)

As approved by the ERB under the 1997 OATS Stipulation and Agreement, the level of spinning reserve to be observed shall be 10.4%. This was derived from the capacity of the largest generating unit on-line (in 1995) expressed as a percentage of the peak system load for the year. In current practice, spinning reserve is usually spread among several units, both for reliability reasons and to provide enough speed (in MW/minute).

4.2.2 Level of Supplemental Reserve (Backup Service)

In its generation planning, NPC has been using the loss of load probability (LOLP). LOLP is a reliability index that indicates the probability that some portion of the load will not be satisfied by the available generating capacity. More specifically, it is defined as the proportion of days per year or hours per year when insufficient generating capacity is available to serve all the daily or hourly loads. LOLP is usually expressed as a ratio of times, e.g., 0.1 days per year equals a probability of 0.000274 (i.e., 0.1/365).

On the other hand, reserve margin is a measure of generating capacity available over and above the amount required to meet the system load requirements. It is defined as the difference between the total available generating system capacity and the annual peak system load, divided by the peak system load, i.e., it is the excess of installed generating capacity over annual peak load expressed as a fraction (or in percentage) of annual peak load. For example, a system with a total installed capacity of 11,500 MW, and which experiences a peak load of 10,000 MW, has a reserve margin of 15%.

In 1995, the LOLP for the NPC grids was set at 24 hours or one day. At this level, the resulting reserve margin was 32.8% average. Thus, the supplemental reserve was computed at 19.6%, i.e., 32.8% less spinning reserve (10.4%) and regulation/load following (2.8%).

4.3 Reactive Supply and Voltage Control Service

This service can be split into a local component and a system component because the transmission customer has sufficient information at its location to control local reactive power demand and the local voltage, while only the system operator has sufficient information to know what the voltage regulation and reactive power requirements are throughout the grid. Because local voltage control is a customer problem, not a grid problem, it cannot be considered an ancillary service.

Reactive losses are much higher than real losses. Voltage drops are predominantly caused by the inductance of the lines and transformers, and can be compensated for by supplying reactive power. Because of the high inductance of lines and transformers, reactive power does not travel well through the grid, so reactive power must be provided much closer to reactive loads than real power needs to be provided to real loads. Voltage regulation is aimed primarily at maintaining voltages within certain ranges, but is also concerned with minimizing temporal variations in voltage.

Voltage is controlled throughout the transmission system through the use of ratio-changing devices (e.g., transformer taps and voltage regulators) and reactive power control devices (e.g., capacitors, reactors, static-var compensators, generators and occasionally synchronous condensers). The system operator must monitor and control these voltages and supply the reactive power requirements of the grid. At certain locations, it may be more economical for a utility to purchase reactive power than it is for the utility to directly supply the reactive power it is responsible for. The equipment used to provide or absorb VARs can be categorized as dynamic (primarily generating units) or static (primarily transmission system equipment).

The cost of supplying reactive power is primarily the capital cost of the equipment (e.g., generators and capacitors). In addition, the operating cost of over- or under-excitation of generating units should be assigned to reactive support. The primary cost of voltage support provided by generators is the opportunity cost associated with the reduction in real-power production capability caused by production or absorption of VARs. Transmission-related voltage control devices have both capital and operating costs.

Because the cost of system voltage support cannot easily be assigned to individual customers, its cost should probably be included in the basic transmission tariff. However, the system operator could purchase VAR support from generators as a separate service.

4.3.1 Overvoltage Correction

TransCo's System Operations implements the appropriate MVAR dispatching during undervoltage situations. To correct overvoltage, the System Operator, through the dispatcher, may inform concerned substation to check and close the required shunt reactors. Depending on the extent of overvoltage, the dispatcher may order selected hydro, geothermal plants and/or thermal plants that are capable of operating on leading power factor based on their reactive capability curve or actual generation limitation to adjust their MVAR generation by going to leading power factor (under-excite). Almost all synchronous generators have considerable control over their terminal voltage and reactive power output. The dispatcher may also order concerned substation with on-load tap changer (OLTC) type power transformer to adjust transformer tap to correct the voltage.

4.3.2 Undervoltage Correction

During undervoltage situations, the dispatcher shall order the concerned substations to check and open shunt reactors in the system and ensure that all transmission lines within their areas of responsibilities are energized, except those that are out for maintenance. The dispatcher may also order on-line plants to raise their operating voltages within permissible limits.

4.4 Black Start Capability

Restoration usually involves restarting the system in several locations at once. In the Luzon grid, there are already pre-determined power restoration highway that will be used to allow the generating plants with black start capability to energize the system. As the restoration progresses, each location contains a growing generation and load balance. These locations must be synchronized to re-establish the interconnection. This process involves matching the frequency and phase angle of adjacent control areas before closing the breakers to connect the areas. Normal operations are resumed when the entire system is reconnected and all loads are restored. Depending on the extent of the blackout, damage to the system, and other load and generation conditions, restoration will take hours to days. Table 1 shows the generating plants with black start capability with their respective power restoration highway.

Table 1. Generating Plants with Black Start Capability

Power Source	Power Restoration Highway	Dispatcher
Angat Hydro	Angat-San Jose-Balintawak-Araneta-Sucat Angat-SanJose-Balintawak-Araneta-Sta Mesa-Rockwell-Urdaneta-Sucat	Generation Dispatcher
Hopewell / Duracom Kalayaan Pump-Storage 2	Hopewell-North Port-Tegen-Sta Mesa-Rockwell-Urdaneta-Sucat-Kamagon-BF Sucat-Malibay-Sunvalley-Sucat Kalayaan 2-Malaya-Dolores-Taguig-Sucat (If Kalayaan 1 is not available)	Transmission Line Dispatcher
Tiwi Geothermal / Bacman	Tiwi-Daraga-Naga-Labo-Gumaca-Kalayaan	Bicol ACC
Kalayaan Pump-Storage 1	Kalayaan 1-Calauan-Makban-Binan-Sucat Kalayaan 1-Calauan-Makban-Binan-Sucat	Southern Tagalog ACC
Pantabangan Hydro	Pantabangan-Cabanatuan-Mexico-Hermosa-Bataan-Olongapo-Botolan	Central Luzon ACC
Binga Hydro	Binga-Ambuklao-Bayombong-Santiago-Magat-Binga-LaTrinidad-Bauang-Labrador	Northern Luzon ACC

Notes: (1) ACC means Area Control Center
(2) Other generating plants with black start capability include Masinloc Coal in Zambales, Bauang Private Power Corp. (BPPC) in La Union and Magat Hydro in Isabela

Selecting the black start-capable generators is somewhat location dependent. Black start generators must be electrically close enough to the other units they are to help restart to be able to energize the transmission lines connecting the two plants. The black start units must also have sufficient capacity and ramping capability to be able to provide the restart power required by the other units. The system operator plays a key role in determining how many units within the grid must have black start capability, where they are to be located, and how to use them in the event of a black out.

Critical features of system black start include:

1. system operators capable of coordinating the effort;
2. black start generating units;
3. communications that operate without grid power. Communications are required for voice between the system operator and the power plants, voice between the system operator and people who operate transmission equipment, voice between adjacent control centers, data

(voltages, phase angles, and equipment status) throughout the system, and control of transmission and generation equipment;

4. controls that operate without grid power;
5. synchronization locations and equipment;
6. power plants capable of being restarted quickly once off-site power has been restored.

TransCo's standard procedure in the implementation of power restoration during a system-wide blackout is attached hereto as Appendix C.

5. Actual System Data

5.1 Approved Levels of Ancillary Services

Since the implementation of open access, TransCo has been applying the ERB-approved percentage requirements of ancillary services in the ERB decision dated June 11, 1997 under ERB Case No. 96-118. The approved levels are shown in Table 2 below.

Table 2. Approved Levels of Ancillary Services

Grid	Load Following and Frequency Regulation	Spinning Reserve	Backup Power
Luzon	2.8%	10.4%	19.6%
Visayas	2.8%	10.4%	19.6%
Mindanao	2.8%	10.4%	19.6%

5.2 Recalculation of Required Level of Ancillary Services

In August 15, 2002, TransCo submitted before the ERC the proposed updated levels of ancillary services based on 2001 system data. Table 3 below shows the recalculated levels of ancillary services for each grid, with the different Visayas grids considered as a single grid.

Table 3. Recalculated Ancillary Services Levels

Grid	Load Following and Frequency Regulation	Spinning Reserve	Backup Power
Luzon	15.5%	11.9%	23.7%
Visayas	23.5%	10.3%	20.7%
Mindanao	21.6%	9.1%	18.1%
Average	17.2%	11.3%	22.7%

Except for the load following and frequency regulation, the recalculated ancillary service levels are within the approved levels. Obviously, the higher level of load following and frequency regulation would impact on the reserve margin requirements of system operator and commercially, on the costs of these services that a transmission customer has to pay. As proposed in the OATS Rules, the appropriate levels of ancillary services shall have to be consulted with the Grid Management Committee to ensure that both technical and commercial issues are taken into consideration.

5.2.1 Calculation for Load Following and Frequency Regulation

The proposed level for load following and frequency regulation for each grid was computed based on the highest hourly load increment expressed as a percentage of the peak system load. Table 4 below shows the actual twelve highest hourly increments, which was used as the basis for the ERC filing.

Table 4. Top 12 Hourly Load Increment (2001)

LUZON		VISAYAS		MINDANAO	
Date/Time	Load Increment	Date/Time	Load Increment	Date/Time	Load Increment
Nov 25, 6 pm	802	Dec 17, 6 pm	180.15	May 31, 9 am	190.81
Apr 16, 9 am	805	Jan 15, 6 pm	181.47	Oct 27, 6 pm	193.79
Nov 17, 6 pm	812	Dec 22, 6 pm	182.23	July 22, 7 pm	197.00
Nov 18, 6 pm	812	Nov 11, 6 pm	185.26	Dec 9, 6 pm	197.00
Dec 24, 6 pm	812	Dec 16, 6 pm	191.13	Dec 18, 11 am	198.00
Dec 9, 6 pm	843	Dec 24, 6 pm	194.43	Nov 24, 6 pm	200.10
Dec 30, 6 pm	854	Dec 31, 6 pm	199.82	Oct 14, 6 pm	204.30
Dec 23, 6 pm	886	Dec 25, 6 pm	206.44	Dec 28, 6 pm	209.20
Nov 19, 9 am	936	Dec 2, 6 pm	210.30	Dec 25, 6 pm	211.70
Apr 16, 8 am	947	Dec 30, 6 pm	216.32	Nov 4, 6 pm	212.20
Dec 16, 6 pm	955	Dec 9, 6 pm	218.90	Dec 16, 6 pm	220.26
Nov 11, 6 pm	991	Jan 12, 6 pm	267.10	Dec 23, 6 pm	233.49
Average	**871.25**	**Average**	**202.80**	**Average**	**205.65**

LUZON		VISAYAS		MINDANAO	
Peak Load May 3, 2 pm	**5,618**	**Peak Load** Aug 27, 8 pm	**863.57**	**Peak Load** Oct 16, 6 pm	**953.84**
Ratio	**15.5%**	**Ratio**	**23.5%**	**Ratio**	**21.6%**

5.2.2 Calculation for Spinning Reserve

As discussed earlier, the spinning reserve capacity is based on the largest generating unit that is on-line. Table 5 below shows the minimum required level of spinning reserve, expressed as percentage of the system peak.

Table 5. Supporting Calculation for Spinning Reserve

Test Year (2000)	System Peak	Largest Unit (MW)	Min. Required	Plant Name	Type of Plant
Luzon	5,450	647	11.9%	Sual	Coal
Visayas	749	78	10.3%	Leyte A	Geothermal
Mindanao	939	85	9.1%	Pulangui IV	Hydro

Note: The largest unit of 647 MW for Luzon is the rated output for one unit of Sual CFTPP. Its net contracted capacity per unit is only 500 MW and thus can only be dispatched at maximum of 560 MW, which is equivalent to only 10.3%.

5.3 2002 System Reserve Profile

The established trend shows that demand in the Luzon grid starts to peak at 11 in the morning, continues to load up at 2 in the afternoon, to finally reach, normally, the day's peak at 7 in the evening. The complete historical record of the daily system peak demand for each period of the day is attached hereto as Appendix D.

Table 6(a) to 6(c) below show the 2002 monthly peak (morning, afternoon, and evening) and the corresponding reserve levels.

Table 6(a). Luzon Grid 2002 System Monthly Peak (Morning)

Month	MORNING (11:00 AM)						
	Demand	Total Available Capacity	13.2% Demand	Load Of Biggest Unit On-line	ACTUAL		
					Capacity Allotted to SR and LFFR		Standby Reserve
						%	
JAN	5060	6861	668	510	799	15.8	1002
FEB	4950	6266	653	500	841	17.0	475
MAR	5200	6018	686	350	708	13.6	110
APR	5500	6739	719	500	751	13.7	488
MAY	5750	7112	759	509	761	13.2	601
JUNE	5750	7858	759	460	1330	23.1	778
JULY	5450	6919	719	440	890	16.3	579
AUG	5400	6749	713	480	778	14.4	571
SEPT	5450	6683	719	500	753	13.8	480
OCT	5550	7676	733	410	877	15.8	1249
NOV	5500	7385	726	400	831	15.1	1054
DEC	5350	7411	706	542	813	15.2	1248

Table 6(b). Luzon Grid 2002 System Monthly Peak (Afternoon)

Month	AFTERNOON (2:00 PM)						
	Demand	Total Available Capacity	13.2% Demand	Load Of Biggest Unit On-line	ACTUAL		
					Capacity Allotted to SR and LFFR		Standby Reserve
						%	
JAN	5160	6727	681	480	685	13.3	882
FEB	5050	6450	667	480	925	18.3	475
MAR	5350	6185	706	350	725	13.6	110
APR	5650	7251	746	500	996	17.6	605
MAY	5850	7252	772	509	782	13.4	620
JUNE	5800	7856	766	480	1278	22.0	778
JULY	5600	6889	739	480	805	14.4	484
AUG	5500	6804	726	480	732	13.3	572
SEPT	5600	7000	739	509	815	14.6	585
OCT	5650	7985	746	350	1086	19.2	1249
NOV	5550	7410	733	450	806	14.5	1054
DEC	5400	7564	713	542	902	16.7	1262

Table 6(c). Luzon Grid 2002 System Monthly Peak (Evening)

Month	EVENING (7:00 PM)						
	Demand	Total Available Capacity	13.2% Demand	Load Of Biggest Unit On-line	ACTUAL		
					Capacity Allotted to SR and LFFR		Standby Reserve
						%	
JAN	5240	6882	692	500	730	13.9	912
FEB	5100	6368	673	480	713	14.0	555
MAR	5300	6485	700	400	811	15.3	374
APR	5450	6797	719	500	742	13.6	605
MAY	5650	7229	746	500	939	16.6	640
JUNE	5600	7648	739	480	1222	21.8	826
JULY	5400	6943	713	450	938	17.4	605
AUG	5400	6816	713	440	834	15.4	582
SEPT	5450	7023	719	509	873	16.0	700
OCT	5600	7981	739	420	1010	18.0	1371
NOV	5600	8142	739	420	836	14.9	1706
DEC	5560	7545	734	350	784	14.1	1201

Although the reserve margin varied from time to time, the ancillary service level had been sufficient to satisfy the grid's requirements. In providing these services, TransCo makes sure that there are sufficient generating units that are on-line and producing energy, and equipped with AGC equipment, and that can change output quickly (MW/minute) over an agreed upon range (MW). Table 7 below lists down the generating plants equipped with AGC.

Table 7. List of Generating Plants Equipped with AGC

Generating Plant	Installed Capacity (MW)
Agus IV Hydro	158
Angat (Main) Hydro	200
Casecnan Hydro	140
Calaca 2 Coal-Fired	300
Ilijan Natural Gas	1,200
Kalayaan 1&2 Pumped Storage	300
Magat Hydro	360
Malaya Thermal	650
Pagbilao Coal-Fired	764
Sual 1&2 Coal-Fired	1,294

The capability of the said plants to respond and provide the required services may depend on the operating range of the AGC. This should be part of the testing that the system operations must undertake to determine the actual dependable AGC-capability of these plants.

In addition, there are current contractual arrangements that must be taken into consideration in order for the plants to participate in providing ancillary services. For example, Casecnan Hydro is under the jurisdiction of National Irrigation Administration (NIA) and representation should be made if the plant can participate in providing load following and regulation. Furthermore, hydro plants capability is dependent on the reservoir elevation and in some cases, NIA requirements.

6. Conclusion

The foregoing discussions have: (i) provided a detailed description and operational characteristics of each ancillary services; (ii) established the need for the ancillary services and the appropriate level for each service; and (iii) demonstrated ancillary services have long been provided to the system by NPC/TransCo.

Under the WESM, some of the ancillary services may have to be integrated into the spot market where the procurement, provision, accounting, and settlement of such services are done through market mechanisms. Ultimately, as the spot market implements market-based pricing for energy, it will likely implement the same on generator-provided ancillary services.

TransCo/NPC has long been providing the ancillary services requirements of the grid. If there had been no frequency regulation, load following, and spinning reserve services, the system frequency would have been unacceptably erratic. Worse, both system frequency and system voltage would have collapsed every time a generator trips out.

These services are being provided not without an acceptable measurement to ensure that such services exist. Every month, transmission customers are provided the exact amount of energy imbalance service that NPC/TransCo provided – down to the last kWh. Every hour (four 15-minute periods) of the month, the exact amount of actual output of a transmission customer's designated generation facility is measured and recorded to determine the amount of generation capacity that ancillary service is backing up any deficiency between scheduled hourly output and actual output. Every four seconds, the frequency of the system is measured and recorded to determine whether the system's total generation supply is able to match the total load.

The appropriate levels of ancillary services shall have to be consulted with the Grid Management Committee to ensure that both technical and commercial issues are taken into consideration. The Committee should develop a methodology in determining a more balance level of ancillary services required under the spot market.

Appendix A: 1997 NPC OATS Definitions

The following definitions of and discussions on ancillary services are part of the Stipulation and Agreement approved by the ERB in 1997.

Schedule 1: System Operations and Planning

System operation and planning includes various services provided by the Transmission Provider and the System Control Operator. System operations and planning costs are incurred on behalf of all Transmission Customers. As such annual system operations and planning costs are included in the rate for power Delivery Service set forth in the Tariff and are not separately stated.

Inasmuch as the System Control Operator and the Transmission Provider need not belong to the same business organization, this service may be provided separately by an independent system operator.

Schedule 2: Load Following and Frequency Regulation Service

Load Following and Frequency Regulation Service provides generating capacity necessary to adjust total system generation over short periods of time (e.g., minutes) to match system load changes that result from random fluctuations in total Transmission System load. Transmission Customer must either (1) obtain load following capacity from its own Grid Generating Resources, (2) obtain load following reserve service from another Transmission Customer under separate agreement, or (3) obtain Load Following Frequency Regulation Service from the Transmission Provider as provided herein.

Any Grid Generating Resource that is designated as load following capacity must, during all times that is so designated, be dedicated to the grid Load Following and Frequency Regulation Service capacity pool under the control of the system Control Operator. If such load following capacity is not obtained from the Transmission Provider, it must be approved by the System Control Operator as an acceptable load following resource. In making this decision the System Control Operator will take into account unit characteristics and other relevant factors in the System Control Operator’s sole judgment. The System Control Operator shall not unduly discriminate against a Transmission Customer’s proposed self-supplied load following capacity resources in making its determination.

The requirement for Load Following Capacity shall be specified by the Transmission Provider in terms of a Load Following Reserve Margin, which is the required reserve margin expressed as a percentage of average monthly maximum system peak demand (net of plant station use). The amount of required Load Following Capacity shall equal the product of Transmission Customer's firm Contract Transmission Capacity and the Load following Reserve Margin so established. Load Following and Frequency Regulation Service provided by the Transmission Provider shall be charged at a rate per kilowatt set forth in the Tariff as approved by the Energy Regulatory Board.

The Load Following Reserve Margin shall be subject to revision by the System Control Operator based on the required level of total system Load Following Capacity and average monthly maximum system demand. The Transmission Provider shall inform Transmission Customer of any change in the Load Following Reserve Margin and the reasons for such change, and provide sufficient time for Transmission Customer to make arrangements for the change. The initial Load Following Reserve Margin shall be 2.8%.

If the System Control Operator determines that additional load following and frequency regulation capacity is required due to the demands imposed by a particular customer's. all the costs of that additional load following and frequency regulation capacity shall be assigned to that customer.

Schedule 3: Reactive Supply and Voltage Control Service

Reactive Supply and Voltage Control Service is related to the maintenance of an acceptable voltage profile in the Transmission System during normal and contingency conditions. For this purpose, System Control Operator has to ensure that adequate reactive power generation and absorption capabilities are maintained in all regions of the Transmission System.

Reactive power compensation is required to be supplied by generating units under normal system operations. Transmission Provider's Application under Section 5 of the Terms includes a declaration of the normal range of reactive, power (VAR) capability of each generator included in Transmission Customer's Grid Generating Resources. Under Reactive Supply and Voltage Control Service Transmission Customer has the option of contributing to system reactive power compensation or paying a charge to Transmission Provider.

If Transmission Customer does not agree to contribute reactive power compensation from any or all of its Grid Generating Resources to a grid reactive power compensation pool under the control of System Control Operator, Transmission Customer shall be charged monthly by Transmission Provider based on the total deficiency. In this event the deficiency shall be computed as the average of the magnitude of the leading and lagging VAR capability of each unit not dedicated to the grid pool, such that total deficiency (VARh) shall be computed as the product of the VAR deficiency and the hours in the billing periods. Transmission Provider shall charge Transmission Customer for the total VARh deficiency for the billing period at the rate set forth in the Tariff as approved by the Energy Regulatory Board.

If the Transmissions Customer agrees to contribute reactive power compensation from any of its Grid Generating Resources, the full declared reactive power capability of each such Transmission Customer generating unit on line at any time must be dedicated to a grid reactive power compensation pool under the control of System Control Operator. If at any time System Control Operator requests Transmission Customer to dispatch an operating unit's reactive power capability, and Transmission Customer fails to follow such dispatch requests, Transmission Customer shall be deemed to be deficient in is reactive power capability for the number of hours covered by such dispatch requests and shall be charged by Transmission Provider for such deficiency based on the requests of System Control Operator. Total deficiency (VARh) for each event shall be computed as the product of the VAR deficiency and the hours covered by the dispatch request. Transmission Provider shall charge Transmission Customer for the total VARh deficiency accumulated for all Tariff as approved by the Energy Regulatory Board.

If Transmission Customer responds fully to System Control Operator request for reactive compensation, Transmission Customer shall be deemed in compliance with its obligation under Reactive Supply and Voltage Control Service.

Should System Control Operator request that Transmission Customer dispatch unit at a VAR level in excess, either leading or lagging of its declared capability, and Transmission Customer provides such service in response, Transmission Provider shall compensate Transmission Customer for all VAR-hour output provided in excess of the unit's declared capability to satisfy System Control Operator's dispatch request. The rate of compensation shall be the rate set forth in the Tariff.

In each month the Transmission Provider shall determine the net amount of revenue received from deficiency charges less costs incurred for excess compensation. Such net amount, whether credit or debit, shall be distributed such all Transmission Customers in proportion to their Load Ratio Share. Such allocated amount shall be set forth separately on the bill to Transmission Customer.

Schedule 4: Spinning Reserve Service

Spinning Reserve Service provides generating capacity necessary to respond immediately to infrequent, but usually large, failures of generating units or transmission plant. This is in contrast to Load Following and Frequency

Regulation Service, who relates to changes in system loads. Spinning Reserve Service shall be limited to a period not exceeding 30 minutes. Continued supply service for periods in excess of 30 minutes shall be provided under the terms of Back-Up Service. Transmission Customer must either (1) provide spinning reserve capacity from its own Grid Generating Resources, (2) obtain spinning reserve service from another Transmission Customer under separate agreement, or (3) obtain Spinning Reserve Service from Transmission Provider as provided herein.

Any Grid Generating Resource that is designated reserve capacity must, during all times it is so designated, be dedicated to the grid Spinning Reserve Service capacity pool under the control of the System Control Operator. If such spinning reserve capacity is not obtained from the Transmission Provider, it must be approved by the System Control Operator as an acceptable spinning reserve resource. In making this decision the System Control Operator will take into account unit characteristics and other relevant factors in the System Control Operator's sole judgment. The System Control Operator shall not unduly discriminate against a Transmission Customer's proposed self-supplied spinning reserve capacity resources in making its determination.

The requirement for Spinning Reserve Capacity be specified by the Transmission Provider in terms of a Spinning Reserve margin, which is the required reserve margin expressed as a percentage of average monthly maximum system peak demand (net of plant station use). The amount of required Spinning Reserve Capacity shall equal the product of Transmission Customer's firm Contract Transmission Capacity and the Spinning Reserve Margin so established. Spinning Reserve Service provided by the Transmission Provider shall be charged at a rate per kilowatt set forth in the Tariff as approved by the Energy Regulatory Board.

The spinning Reserve Margin shall be subject to revision by the System Control Operator based on the required level of total system Spinning Reserve Capacity and average monthly maximum system demand for an annual period. The Transmission Provider shall inform Transmission Customer of any change in the Spinning Reserve Margin and the reasons for such change, and provide sufficient time for Transmission Customer to make arrangements for the change. The initial Spinning Reserve Margin shall be 10.4%.

If the System Control Operator determines that additional spinning reserve capacity is required due to the demands imposed by a particular customer, all the costs of that additional capacity shall be assigned to that customer.

Schedule 5: Security Redispatch

For a variety of reasons the transmission system can develop bottlenecks which may mean that firm service contracts cannot be fulfilled. In that case the transmission provider or transmission service customer may arrange an alternative supply; this is likely to lead to an increase in operating cost caused by running generators out of merit order.

If a bottleneck can be attributed to the actions of a specific customer the full costs of alleviating the bottleneck shall be borne by that customer. This may require that System Control Operator to perform studies to link bottlenecks to specific customers.

The cost of alleviating non-specific bottlenecks shall be determined by the System Control Operator and apportioned among all Transmission Customers in proportion to the Load Ratio Shares. Such amount shall be set out separately in the monthly bill to Transmission Customer.

Schedule 6: Schedule Imbalance Service

Schedule Imbalance Service provides an incentive for Transmission Customer to operate its Grid Generating Resources in a predictable manner for purposes of system control. Each day Transmission Customer will be required to provide System Control Operator an expected hourly generation schedule for each unit included in its Grid Generating Resources to the System Control Operator as required by the Transmission Operating Agreement. A schedule imbalance shall be deemed to occur in any hour in which actual generation on any unit differs from its scheduled generation by greater than 1.5% without suitable cause. Suitable cause may include dispatch instructions from the System Control Operator, forced outage, or other event as may be provided in the Transmission Operating Agreement.

Transmission Provider shall charge Transmission Customer for the deviation, whether excess or deficiency, greater than 1.5% of scheduled output determined by System Control Operator for each hour. The total deviation (kWh) accumulated for all imbalance events during the billing period shall be charged at the rate set forth in the Tariff as approved by the Energy Regulatory Board.

In each month the Transmission Provider shall determine that total amount of revenue received from all Transmission Customers subject to Schedule Imbalance Service and shall distribute such amount among all Transmission Customers in proportion to their Load Ratio Share. Any charges for schedule deviation and the allocated amount of revenue received shall each be set forth separately on the bill to Transmission Customer.

Schedule 7: Loss Compensation Service

Real Power Losses are associated with all Power Delivery Service. The Transmission Provider is not obligated to provide capacity and energy to supply Transmission Customer's Real Power Losses. Each Transmission Customer must supply capacity and energy for losses associated with the output of its Grid Generating Resources. This will be accomplished by attributing the average system energy loss factor (transmission losses as percent of net generation), determined to the nearest 0.01%, to the output of Transmission Customer's Grid Generating Resources to determine that amount of power and energy deemed to have been delivered to Transmission Customer's Point (s) of Delivery. Loss factors shall be determined separately for each grid. This will result in all Transmission Customers (including the Transmission Provider) sharing proportionately in the supply of transmission real power losses. The requirement for Transmission Customer to provide for its own losses shall not be affected by any agreement that Transmission Customer may have with its supplier (s).

The applicable loss factor shall be computed by the Transmission Provider based on system net generation, excluding plant station use, for all Grid Generating Resources and total energy delivered to all Point (s) of Delivery for a period of 24 months, which period is considered to be sufficiently long to insure stability in the resulting loss factor. The loss factors shall be recomputed by the Transmission Provider periodically (but not less frequently than once each year) based on the prior 24–month period. The loss factor so computed shall be used until the Transmission Provider has updated such factors. The Transmission Provider shall provide each Transmission Customer a copy of the calculations used to update the loss factors.

Power and energy delivered to Transmission Customer at its Point (s) of Delivery from its Grid Generating Resources shall be determined by reducing the output of such facilities, measured at the Point (s) of Receipt, by the loss factor then in effect.

Initial loss factors computed for the 24–month period through December 1995 are set forth below.

Luzon	2.44%
Visayas	3.70%
Mindanao	4.50%

Schedule 8: Startup Service

Start–Up Service refers to the supply of capacity and energy to a generating unit in preparation for its synchronization to the transmission grid.

Transmission Provider shall consider the generating capacity requirement for start–up service to be part of the ordinary cyclic variation characteristic of all system loads, and which is provided under the Load Following and Frequency Regulation Service. Therefore there shall be no separate charge for the generating capacity when such service is coordinated with the System Control Operator. The Transmission Provider shall not be obligated to provide firm transmission or other system constraint exists in accordance with Section 9 of the Terms.

The Transmission Customer must provide the energy required for start – up whenever it is possible to do so by (1) supply from the Transmission Customer's other Grid Generating Resources; (2) black start capability of the generating station concerned; (3) energy purchased from other Transmission Customer(s); (4) repayment in kind to the Transmission Provider. Should an instance arise where none of these options is available, the Transmission Customer shall reimburse the Transmission Provider for start – up energy at the actual incremental cost of such energy.

Schedule 9: Maintenance Service

Maintenance service refers to the supply of electricity to a Transmission Customer's generating station while it is out of service for maintenance or repair.

Transmission Provider shall consider the generation capacity requirement for Maintenance Service to be part of the ordinary cyclic variation characteristic of all system loads, and which is provided under the Load Following and Frequency Regulation Service. Therefore there shall be no separate charge for the capacity when such service is coordinated with the System Control Operator. Transmission Provider shall not be obligated to provide firm transmission capacity when the Transmission Provider deems that a transmission or other system constraint exists in accordance with Section 9 of the Terms. Transmission Customer may use a portion of its firm Contract Transmission Capacity to continue service to a generating station under these circumstances.

The Transmission Customer must provide the energy required for maintenance whenever it is possible to do so by: (1) supply from the Transmission Customer's other Grid Generating Resources; (2) energy purchased from other Transmission Customer(s); or (3) repayment in kind to the Transmission Provider under arrangements deemed acceptable to the Transmission Provider. Should an instance arise where none of these options is available, the Transmission Customer shall reimburse the Transmission Provider for maintenance energy at the actual incremental cost of such energy.

Schedule 10: Backup Service

Back–up service refers to the supply of capacity and energy to a Transmission Customer's Transmission System Load for periods during which the Transmission Customer's Grid Generating Resources is experiencing an outage, whether scheduled or unscheduled, and Spinning Reserve Service does not apply all Transmission Customers must either (1) provide back–up capacity from its own Grid Generating Resources, (2) obtain back–up service from another Transmission Customer under separate agreement, or (3) obtain Back–up Service from the Transmission Provider as provided herein.

Any Grid Generating Resources that is designated as back-up capacity must, during all times that it is so designated, be dedicated to the grid Back-up Service capacity pool and under the control of the System Control Operator. If such back-up is not obtained from the Transmission Provider, it must be approved by the Transmission Provider as an acceptable back-up resource. In making this decision the System Control Operator will take into account generating unit availability performance, location, unit characteristics, compatibility with the existing generation mix, and other relevant factors in the System Control Operator's sole judgment. The System Control Operator shall not unduly discriminate against a Transmission Customer's proposed self-supplied back-up capacity resources in making its determination.

The requirement for back-up capacity shall be specified in terms of a Reserve Plant Margin, which is the back-up capacity expressed as a percentage of firm Contract Transmission Capacity. The Transmission Provider shall specify the required back Reserve Plant Margin, which shall exclude requirements for spinning reserve. Transmission Customer shall be required to obtain, as described above, back-up capacity equal to the product of such Reserve Plant Margin and firm Contracted Transmission Capacity. Back-Up Service provided by the Transmission Provider will be charged at a rate per kilowatt set forth in the Tariff as approved by the Energy Regulatory Board.

The Reserve Plant Margin shall be subject to revision considering the circumstances of the grid (s), planned system reliability margins, and other relevant factors as determined by the System Control Operator. The Transmission Provider shall inform Transmission Customer of any change in the Reserve Plant Margin and the reasons for such change and provide sufficient advance notice of the need for Transmission Provider to make arrangements for the change in required back-up reserves. The initial Reserve Plant Margin shall be 19.6%.

Appendix B: ALD Schedules in the Luzon Grid

Appendix C: Power Restoration on a System Blackout

Appendix D: 2002 Daily Reserve Profile (Luzon Grid)

References

[1] Hirst, Eric and Brendan Kirby. "Unbundling Generation and Transmission Services for Competitive Electricity Markets: Examining Ancillary Services," Oak Ridge National Laboratory, January 1998.

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