ANNEX C

Definite Rules and Procedures to be used in the Price Determination Methodology (PDM)

1.0 DISPATCH AND PRICING ALGORITHM

The Market Dispatch Optimization Model (MDOM) as described in the PDM will determine the optimal dispatch schedule for a given trading interval. The MDOM likewise determines the Nodal Energy Prices at all trading nodes in the market network model and reserve prices for all reserve regions resulting from the optimal dispatch.

1.1 The Basic Algorithm of the MDOM

The MDOM aims to maximize the economic gain derived from electricity trades in the market, considering the constraint conditions imposed by the system. The basic algorithm is given in the mathematical formulation below, viz:

OBJECTIVE FUNCTION

Maximize the economic gain from trade, where:

$$\textbf{ECONOMIC GAIN} = \sum_{i}^{n}(DB)_i(CDB)_i - \sum_{i}^{n}(G)_i(CG)_i - \sum_{i}^{n}(R)_i(CR)_i - (VP)_m$$

where:

DB_i - Demand bid quantity (MW) of customer i

CDB_i - Price of demand bid of customer i

G_i - Energy quantity offer of generator i

CG_i - Price of energy offer of generator i

R_i - Reserve quantity offer of ancillary services provider i

CR_i - Cost of reserve offer of ancillary services provider i

VP_m - Penalty for not satisfying constraint at element m of the market network mode where m refers to the particular network element. Network violations refer to thermal and voltage limits

CONSTRAINTS

$G_{i,min} \le G_i \le G_{i,max}$	generator offer limits where $G_{i,min}$ is the minimum value and $G_{i,max}$ is the maximum value of the offered block of quantity of generator i
$G_i + R_i \le G_{i,max}$	the summation of generator offer plus reserve offer of generator i must be less than or equal the maximum offered quantity $G_{i,max}$
$F_{i,j} \le Fmax_{i,j}$	the power flows from location i to location j should be less than or equal the network element capacities.
$\sum G_i = \sum D_i + Losses$	the summation of generation must match the summation of demand (D) plus the consumed losses (L) in delivering the power from generators to loads

The solution of the optimization process shall satisfy the pre-defined constraints. Constraint violation penalties shall be imposed for allowing violations to such constraints in the system. The constraints to be satisfied are:

- Constraints representing limits on generation offer, demand bid and reserve quantities;
- Constraints representing the technical characteristics of reserve facility categories;
- Energy balance equations for each node;
- Constraints representing limitations on the plants ramp rates;
- Constraints defining power system reserve requirements;
- Network constraints;
- Loss and impedance characteristics of market network lines;
- Constraints on HVDC link operation;
- Power flow equations;
- Any overriding constraints; and
- Any additional constraints due to ancillary services or system security requirements.

The output of the MDOM

The optimization process will produce the following outputs:

- The cost of the solution;
- Generation output levels (MW) for each generator offer band;
- Reserve for each reserve offer band;
- Scheduled load for each demand bid band;
- Transmission line flows;

- Transmission line and system losses;
- Nodal energy prices at each node; and
- Regional reserve prices.

1.2 The Determination of Nodal Pricing

The price at a particular node in the system (i.e. the nodal price), signals the *"scarcity value"* of electricity given the supply and demand interaction at that node, and in addition, the relevant opportunity cost of supplying an *"incremental"* (i.e. additional) amount of electricity at that location. Consideration is placed on the incremental amount of electricity supplied at a node because this will alter or affect the flow of energy and losses to other nodes in the system.

Under an unconstrained system, the market-clearing price (MCP) is set by one "marginal plant" (i.e. the system marginal price). However, the situation is different if the system is constrained because this will affect the relevant flows of electricity and may result in a situation where there will be more than one marginal plant in the system. This occurrence is brought about by line limitations that may impede the supply of cheaper generators from one area into another. The end effect is for different plants to be setting the MCPs in different nodes in the system due to line constraints.

In the MDOM, said marginal prices at specific locations (i.e. nodal prices) will be computed on the basis of the resulting marginal plants' contribution, in terms of cost, to an incremental load of one megawatt-hour occurring in a particular location or node. If there will be more than one marginal plant that can serve the incremental one megawatt-hour at a particular node as in the case of a constrained system, then the price at that node will be the relative contribution of these marginal plants to the incremental one-megawatt hour load multiplied by the respective marginal plants' price offers. The resulting value is the marginal price (MP) computed by the MDOM.

Mathematically, the marginal price is given by the formula:

$$\text{Marginal Price} = \sum \left[\frac{\Delta G_i}{\Delta D_j} \text{ x } P_i \right]$$

where:

ΔG_i – change in dispatched quantity of generator i
ΔD_j – incremental demand at bus j
P_i – offered price of generator i

1.3 The Price Adjustments to Reflect Transmission Losses

With due consideration to the change in power flows and losses in the system, the respective marginal prices (MPs) should be adjusted to reflect this condition and signal into the market the relevant cost to produce and purchase electricity at the subject nodes.

Taking into consideration the above, the various MPs should be adjusted by multiplying the MPs by the marginal loss factors with respect to a “reference bus”. This results to the loss adjusted MPs for each node or nodal prices in the system.

The “reference bus” where loss factors will be referenced must be chosen in a manner that would reflect the actual energy loss in the course of moving energy from injection points to various customer off-take points. The location of the “reference” bus must be chosen in such a way that it rest in the notional center of the network so as to reflect a relatively balanced allocation of transmission loses to all participants. In this way, the nodal prices are adjusted without undue bias due to location. Refer to **Appendix B** for the determination of marginal loss factors.

2.0 FORMULATION OF THE OBJECTIVE FUNCTION AND CONSTRAINTS EQUATIONS

For illustration purpose, the objective function and constraint equations were formulated for the net benefit maximization for the WESM MDOM.

The data used in the examples includes the following:

- Market network model – a six node example as shown in the single line diagram;
- Transmission lines capacity and dc characteristics;
- System participants profiles – five generators, four loads representing nodal net forecasted loads, and four demand bid blocks;
- Bids and offers;
- System regulating and contingency reserves requirement.
- Violation penalties are not included.

Table C-1
Transmission Network Data- DC Representation

From Node	To Node	Line Characteristics		Capacity
		Line R	Line X	MW
1	2	0.00870	0.06780	350
1	5	0.01350	0.10530	350
2	3	0.00315	0.02450	700
2	6	0.00165	0.01295	700
3	4	0.00220	0.01730	350
4	5	0.00330	0.02590	350
5	6	0.00180	0.01440	350

Table C-2
Generator and Load Data

Node	Generator Data			Load Data	
	ID	MW_{MAX}	MW_{MIN}	ID	MW
1	A	150	0	-	0
2	C	300	0	-	0
3	B	400	0	3	300
4	D	300	0	4	150
5	-	-	-	2	200
6	E	600	0	1	350

Figure C-1
Market Network Model Diagram (6-Node Example)

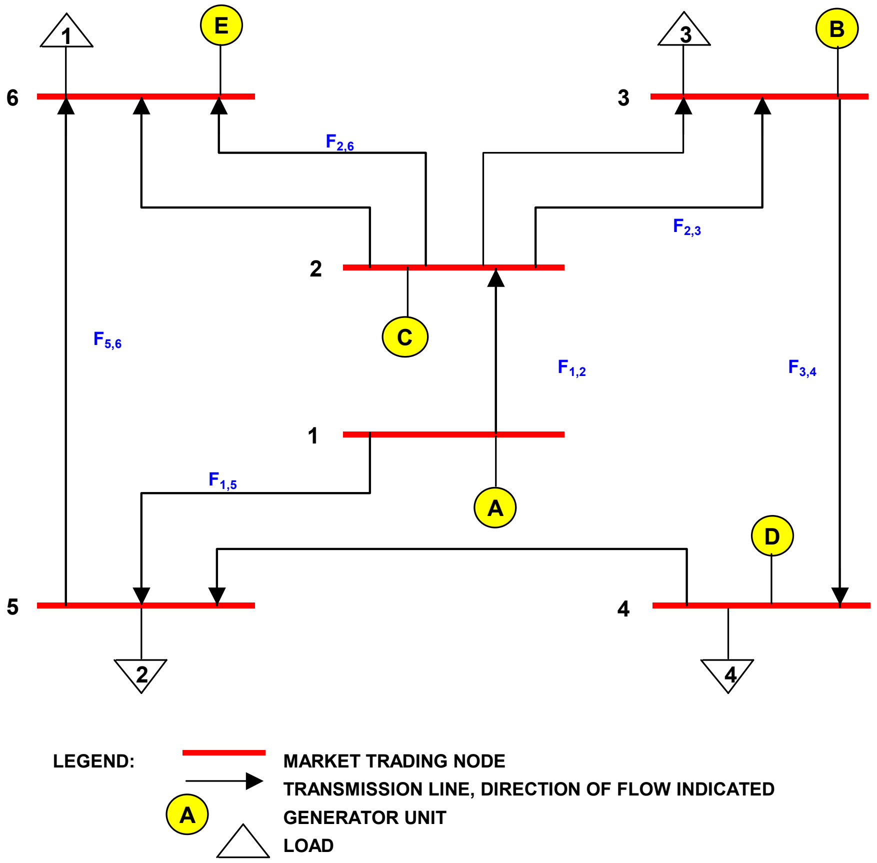


Table C-3
Input Table-6 Node Example

INPUT

RESERVE REQUIREMENT			
REG. (MW)	3.0%	CONT (MW)	10.0%
	30		100

NODE	TOTAL DEMAND	NET LOAD FORECAST	DEMAND BID		GEN CAP (MW)	GEN OFFER		REG RES. OFFER		CONT RES. OFFER	
			QTY (MW)	PRICE (P//MWh)		QTY (MW)	PRICE (P/MWh)	QTY (MW)	PRICE (P/MWh)	QTY (MW)	PRICE (P/MWh)
1	0.00	0.00	0.0	0.00	600.0	600.0	200.00	18.0	220.00	0.0	0.00
2	0.00	0.00	0.0	0.00	400.0	400.0	1421.43	12.0	426.43	50.0	821.43
3	330.00	300.00	30.0	1400.00	150.0	150.0	841.43	5.0	925.57	0.0	0.00
4	165.00	150.00	15.0	1700.00	300.0	300.0	1450.00	20.0	1530.47	50.0	2233.47
5	220.00	200.00	20.0	1900.00	0.0	0.0	0.00	0.0	0.00	0.0	0.00
6	385.00	350.00	35.0	1300.00	600.0	600.0	3098.48	20.0	1546.24	50.0	1049.24
TOTAL	**1100.00**	**1000.00**	**100.0**		**2050.0**	**2050.0**		**75.0**		**150.0**	

2.1 WESM MDOM ALGORITHM

For the sample six-node market network model, the equation of the objective function for the WESM MDOM would be:

Maximize

$$
\begin{aligned}
\textbf{NET BENEFIT} \quad = \quad & [DB_3xCDB_3 + DB_4xCDB_4 + DB_5xCDB_5 + DB_6xCDB_6] \\
- \quad & [G_1xCG_1 + G_2xCG_2 + G_3xCG_3 + G_4xCG_4 + G_6xCG_6] \\
- \quad & [Rr_1xCRr_1 + Rr_2xCRr_2 + Rr_3xCRr_3 + Rr_4xCRr_4 + Rr_6xCRr_6] \\
- \quad & [Rc_2xCRc_2 + Rc_4xCRc_4 + Rc_6xCRc_6\ ]
\end{aligned}
$$

Subject to the following constraints:

Input Related Limits:

Generator unit constraints: (Generator unit scheduled output should be within its minimum and maximum offered capacity)

$$
\begin{array}{lllllllllll}
G_{1,min} & \leq & G_1 & \leq & G_{1,max} & \qquad & 0 & \leq & G_1 & \leq & 600 \\
G_{2,min} & \leq & G_2 & \leq & G_{2,max} & & 0 & \leq & G_2 & \leq & 400 \\
G_{3,min} & \leq & G_3 & \leq & G_{3,max} & & 0 & \leq & G_3 & \leq & 150 \\
G_{4,min} & \leq & G_4 & \leq & G_{4,max} & & 0 & \leq & G_4 & \leq & 300 \\
G_{6,min} & \leq & G_5 & \leq & G_{6,max} & & 0 & \leq & G_6 & \leq & 600
\end{array}
$$

Demand Bids Limits: (Node Demand Bid scheduled quantity ≤ Node Demand Bid bidded)

$DB_3 \le DB_3$ bidded =➔ $DB_3 \le 30$
$DB_4 \le DB_4$ bidded =➔ $DB_4 \le 15$
$DB_5 \le DB_5$ bidded =➔ $DB_5 \le 20$
$DB_6 \le DB_6$ bidded =➔ $DB_6 \le 35$

Reserve Limits:
Regulating reserve scheduled output ≤ Regulating Reserve Offered

$Rr_1 \le Rr_1$ Offered=➔ $Rr_1 \le 18$
$Rr_2 \le Rr_2$ Offered=➔ $Rr_2 \le 12$
$Rr_3 \le Rr_3$ Offered=➔ $Rr_3 \le 5$
$Rr_4 \le Rr_4$ Offered=➔ $Rr_4 \le 20$
$Rr_6 \le Rr_6$ Offered=➔ $Rr_6 \le 20$

Contingency reserve scheduled output < Regulating Reserve Offered
$Rc_2 \le Rc_2$Offered=➔ $Rc_2 \le 50$
$Rc_4 \le Rc_4$Offered=➔ $Rc_4 \le 50$
$Rc_6 \le Rc_6$Offered=➔ $Rc_6 \le 50$

Energy & Reserve Co-optimization Balance: (Generator unit energy plus reserve scheduled output ≤ Generator maximum capability)

$G_1 + Rr_1 + Rc_1 \le G_{1,max}$ =➔ $G_1 + Rr_1 + Rc_1 \le 600$
$G_2 + Rr_2 + Rc_2 \le G_{2,max}$ =➔ $G_2 + Rr_2 + Rc_2 \le 400$
$G_3 + Rr_3 + Rc_3 \le G_{3,max}$ =➔ $G_3 + Rr_3 + Rc_3 \le 150$
$G_4 + Rr_4 + Rc_4 \le G_{4,max}$ =➔ $G_4 + Rr_4 + Rc_4 \le 300$
$G_6 + Rr_6 + Rc_6 \le G_{6,max}$ =➔ $G_6 + Rr_6 + Rc_6 \le 600$

Power flow Limits: (Resulting line flows from node i to node j ≤ line capacity)

$F_{1,2} \le 350$ $F_{1,5} \le 350$ $F_{2,3} \le 700$
$F_{2,6} \le 700$ $F_{3,4} \le 350$ $F_{4,5} \le 350$
$F_{5,6} \le 350$

Balance Equations:

Nodal Balance : (Energy input - Load equals the sum of line flows. Line flows computed based on DC loadflow algorithm)

$$
\begin{aligned}
G_1 - 0 &= F_{1,2} + F_{1,5} \\
G_2 - 0 &= F_{2,1} + F_{2,3} + F_{2,6} \\
G_3 - (D_F + DB)_3 &= F_{3,2} + F_{3,4} \\
G_4 - (D_F + DB)_4 &= F_{4,3} + F_{4,5} \\
0 - (D_F + DB)_5 &= F_{5,1} + F_{5,4} + F_{5,6} \\
G_6 - (D_F + DB)_6 &= F_{6,2} + F_{6,5}
\end{aligned}
$$

System Balance: (The total system scheduled generation equals the summation of nodal net forecasted load plus scheduled demand with price bids plus system loss)

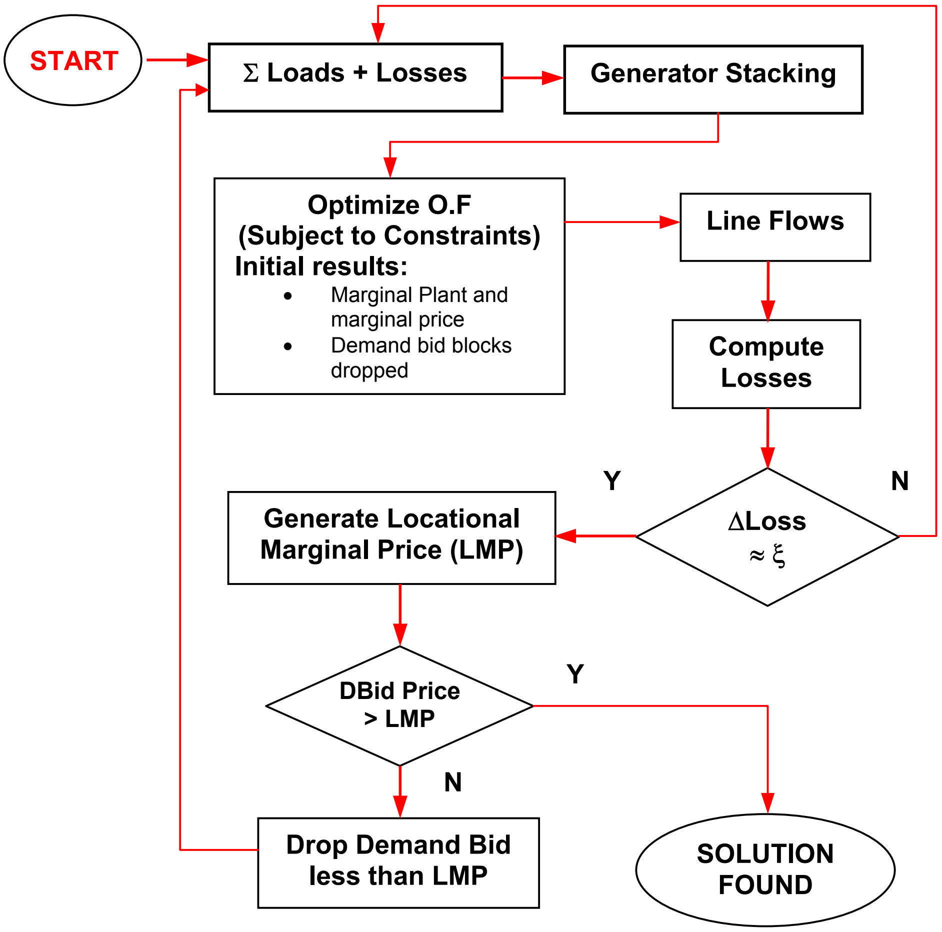
$$\Sigma GENS = \Sigma D_F + \Sigma DB_{SCHED} + \Sigma LOSS$$

Demand Bid Dispatch Checking: For a Demand Bid to be scheduled, Demand Bid Price (CDB) should be greater than the nodal price where the DB is connected.

2.2 The Optimization Process Flow

The process starts with the economic order stacking of generator. From among the possible generation mix combination, the algorithm chooses the least-cost solution that meets the constraints imposed on the system to supply the required load. The line flows and line losses are then computed using dc loadflow algorithm.

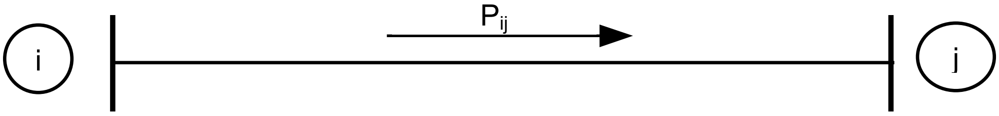
FIGURE C-2
Optimization Process Flow



Refer to Annex A for the numerical examples on the PDM.

APPENDIX A
DC LOADFLOW CONCEPTS

1.0 Power Flow on a Line Between Two Nodes



$$F_{ij} = \frac{(\phi_i - \phi_j)}{X_{ij}} \qquad \text{watts}$$

where:

F_{ij} – power flow in the line connected between bus i and bus j
Φ_I – bus voltage angle of bus i
X_{ij} – reactance of the line connected between bus i and bus j

At any node,

[Power injection – (Node Load + Nodal Loss)] = Summation of Line Flows

$$G_i - D'_i = \sum F_{ij} = \sum \frac{(\phi_i - \phi_j)}{X_{ij}}$$

where:

G_i – power injection or summation of generator outputs at bus i
D'_i – summation of nodal loss and load connected at bus i

Using the six (6) – bus network, the following equations can be formulated based on the relationship above.

Equation 1: $$G_1 - D'_1 = \frac{(\phi_1 - \phi_2)}{X_{12}} + \frac{(\phi_1 - \phi_5)}{X_{15}}$$

Equation 2: $$G_2 - D'_2 = \frac{(\phi_2 - \phi_1)}{X_{21}} + \frac{(\phi_2 - \phi_3)}{X_{23}} + \frac{(\phi_2 - \phi_6)}{X_{26}}$$

Equation 3: $$G_3 - D'_3 = \frac{(\phi_3 - \phi_2)}{X_{32}} + \frac{(\phi_3 - \phi_4)}{X_{34}}$$

Equation 4: $$G_4 - D'_4 = \frac{(\phi_4 - \phi_3)}{X_{43}} + \frac{(\phi_4 - \phi_5)}{X_{45}}$$

Equation 5: $$G_5 - D'_5 = \frac{(\phi_5 - \phi_1)}{X_{51}} + \frac{(\phi_5 - \phi_4)}{X_{54}} + \frac{(\phi_5 - \phi_6)}{X_{56}}$$

Equation 6: $$G_6 - D'_6 = \frac{(\phi_6 - \phi_2)}{X_{62}} + \frac{(\phi_6 - \phi_5)}{X_{65}}$$

Expand the above equations to formulate the Bus Admittance Matrix.

Equation 1: $$G_1 - D'_1 = \left(\frac{1}{X_{12}} + \frac{1}{X_{15}}\right) \bullet \phi_1 - \frac{\phi_2}{X_{12}} - \frac{\phi_5}{X_{15}}$$

$$G_1 - D'_1 = Y_{11} \bullet \phi_1 + Y_{12} \bullet \phi_2 + Y_{15} \bullet \phi_5$$

Equation 2: $$G_2 - D'_2 = \left(\frac{1}{X_{21}} + \frac{1}{X_{23}} + \frac{1}{X_{26}}\right) \bullet \phi_2 - \frac{\phi_1}{X_{21}} - \frac{\phi_3}{X_{23}} + \frac{\phi_6}{X_{26}}$$

$$G_2 - D'_2 = Y_{22} \bullet \phi_2 + Y_{21} \bullet \phi_1 + Y_{23} \bullet \phi_3 + Y_{26} \bullet \phi_6$$

Equation 3: $$G_3 - D'_3 = \left(\frac{1}{X_{32}} + \frac{1}{X_{34}}\right) \bullet \phi_3 - \frac{\phi_2}{X_{32}} - \frac{\phi_4}{X_{34}}$$

$$G_3 - D'_3 = Y_{33} \bullet \phi_3 + Y_{32} \bullet \phi_2 + Y_{34} \bullet \phi_4$$

Equation 4: $$G_4 - D'_4 = \left(\frac{1}{X_{43}} + \frac{1}{X_{45}}\right) \bullet \phi_4 - \frac{\phi_3}{X_{43}} - \frac{\phi_5}{X_{45}}$$

$$G_4 - D'_4 = Y_{44} \bullet \phi_4 + Y_{43} \bullet \phi_3 + Y_{45} \bullet \phi_5$$

Equation 5: $$G_5 - D'_5 = \left(\frac{1}{X_{51}} + \frac{1}{X_{54}} + \frac{1}{X_{56}}\right) \bullet \phi_5 - \frac{\phi_1}{X_{51}} - \frac{\phi_4}{X_{54}} - \frac{\phi_6}{X_{56}}$$

$$G_5 - D'_5 = Y_{55} \bullet \phi_5 + Y_{51} \bullet \phi_1 + Y_{54} \bullet \phi_4 + Y_{56} \bullet \phi_6$$

Equation 6: $$G_6 - D'_6 = \left(\frac{1}{X_{62}} + \frac{1}{X_{65}}\right) \bullet \phi_6 - \frac{\phi_2}{X_{62}} - \frac{\phi_5}{X_{65}}$$

$$G_6 - D'_6 = Y_{66} \bullet \phi_6 + Y_{62} \bullet \phi_2 + Y_{65} \bullet \phi_5$$

In matrix form,

$$\begin{bmatrix} G_1 - D'_1 \\ G_2 - D'_2 \\ G_3 - D'_3 \\ G_4 - D'_4 \\ G_5 - D'_5 \\ G_6 - D'_6 \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & 0 & 0 & Y_{15} & 0 \\ Y_{21} & Y_{22} & Y_{23} & 0 & 0 & Y_{26} \\ 0 & Y_{32} & Y_{33} & Y_{34} & 0 & 0 \\ 0 & 0 & Y_{43} & Y_{44} & Y_{45} & 0 \\ Y_{51} & 0 & 0 & Y_{54} & Y_{55} & Y_{56} \\ 0 & Y_{62} & 0 & 0 & Y_{65} & Y_{66} \end{bmatrix} \begin{bmatrix} \phi_1 \\ \phi_2 \\ \phi_3 \\ \phi_4 \\ \phi_5 \\ \phi_6 \end{bmatrix}$$

In general form,

$$\begin{bmatrix} G_1 - D_1' \\ G_2 - D_2' \\ G_3 - D_3' \\ G_4 - D_4' \\ G_5 - D_5' \\ G_6 - D_6' \end{bmatrix} = \begin{bmatrix} Y_{11} & Y_{12} & Y_{13} & Y_{14} & Y_{15} & Y_{16} \\ Y_{21} & Y_{22} & Y_{23} & Y_{24} & Y_{25} & Y_{26} \\ Y_{31} & Y_{32} & Y_{33} & Y_{34} & Y_{35} & Y_{36} \\ Y_{41} & Y_{42} & Y_{43} & Y_{44} & Y_{45} & Y_{46} \\ Y_{51} & Y_{52} & Y_{53} & Y_{54} & Y_{55} & Y_{56} \\ Y_{61} & Y_{62} & Y_{63} & Y_{64} & Y_{65} & Y_{66} \end{bmatrix} \begin{bmatrix} \phi_1 \\ \phi_2 \\ \phi_3 \\ \phi_4 \\ \phi_5 \\ \phi_6 \end{bmatrix}$$

where: $(G_i – D_i')$ – net injection at bus i
Φ_I – bus voltage angle of bus i
Y_{ii} – diagonal elements
= sum of admittances directly connected to bus i
Y_{ij} – off-diagonal elements
= negative of the admittance connected between bus i and bus j

1.1 Computation of Losses

$$P_{L(ij)} = 3 \bullet I_{ij}^2 \bullet R_{ij} \quad \text{watts}$$

$$I_{ij} = \frac{F_{ij}}{\sqrt{3} \bullet V_j} \quad \text{amperes}$$

$$_{PU}R_{ij} = \frac{R_{ij}}{Z_B} \quad \text{and} \quad Z_B = \frac{V_B^2}{MVA_B}$$

$$R_{ij} = \frac{_{PU}R_{ij} \bullet V_B^2}{MVA_B}$$

where:
$P_{L(ij)}$ – power loss of line connected between bus i and bus j (watts)
I_{ij} – current flowing through the line connected between bus i and bus j (amperes)
R_{ij} – actual value of resistance of the line between bus i and bus j
V_j – bus voltage at the receiving end of the line
$_{PU}R_{ij}$ – per unit value of resistance of the line between bus i and bus j
Z_B – base impedance
V_B – base voltage
MVA_B – base power

Therefore,

$$P_{L(ij)} = 3 \bullet \left(\frac{F_{ij}}{\sqrt{3} \bullet V_j} \right)^2 \bullet \left(\frac{{}_{PU}R_{ij} \bullet V_B^2}{MVA_B} \right)$$

Since the system rated voltage is taken as the base voltage, $V_j = V_i = V_B$.

$$P_{L(ij)} = \frac{F_{ij}^{\ 2} \bullet {}_{PU}R_{ij}}{MVA_B}$$

Note: Line losses are added to the demand at the receiving end of the line.
Receiving end – end of the line where the power flow is directed.

APPENDIX B
DETERMINATION OF LOSS FACTOR

WESM Rules require that the Market Dispatch Optimization Model be able to determine the energy prices at all trading nodes. This means that a set of nodal prices be calculated for all locations at which there are generators or loads. The use of Marginal Loss Factors (MLF) provides a practical approximation to the nodal pricing that would be used in a theoretically ideal electricity market. MLFs provide information as to how the value of electrical energy varies with location that guides the operation of existing generation and consumption as well as new entrants with regard to siting and technology decisions.

Loss Factors are used to represent the change in network losses that occur due to small increase in load at the connection point, compared to the change that would occur if the loads were located at the Reference Bus. Conceptually, this can be achieved by modeling a small increase in load at each generator and load connection point and determining the resultant increase in generation required to meet that load increase assuming it is supplied from a generator located at the Reference Bus.

The LF is defined in terms of this small increase in load as:

$$\begin{aligned} LF &= \frac{\text{change in generation at the reference bus}}{\text{change in load at the connection point}} \\ &= \frac{\text{change in network losses} + \text{change in load}}{\text{change in load}} \end{aligned}$$

$$LF = 1 + \Delta_{\text{loss}} / \Delta_{\text{load increment}}$$

where:

Δ_{loss} = change in network loss
$\Delta_{\text{load increment}}$ = incremental increase in load at connection point

Determination of Loss Factor from Load Flow Simulation

The process for calculating the marginal loss factor equation is as follows:

1. Obtain a load flow case setup to reflect the power system conditions for which the loss factors are to be calculated.
2. Solve the load flow case.
3. Model a dummy generator (P^{O}_{Ref}) at the Reference Bus. The dummy generator should be modeled as the swing generator.
4. Re-solve the loadflow and record the output from the dummy generator. The output at this stage should be close to 0 MW.
5. Increase the load at Bus i for which the MLF is to be determined by 1 MW.

6. Resolve the loadflow case and again record the output from the dummy generator (P^{N}_{Ref}).
7. The LF for Bus i can be calculated as:

$$LF = 1 + (P^{N}_{Ref} - P^{O}_{Ref} - D)/1$$

where:

P^{N}_{Ref} = output of dummy generator at Reference Bus resulting from 1MW incremental load at Bus i

P^{O}_{Ref} = output of dummy generator at present state (0 MW)

D = incremental load at Bus i (1 MW is used as incremental load)

Bus i = bus where incremental load is drawn

LF = loss factor of Bus i to Reference Bus

8. Repeat steps 1 to 7 for all other Bus i.