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**Request IR-1:**

**Reference: Update of Scotian WindFields DR-01 and DR-01**

**SWEB requests that Scotian WindFields Inc. DR-01 and DR-02 (included in the September 1, 2015 Application as Appendices 13E and 13F, respectively, and later as 14A) are updated to include all relevant values of changes to tariffs and related frameworks, with respect to the September 1, 2015 Application.**

Response IR-1:

Please refer to **Attachment 1** and **Attachment 2,** also provided electronically.

## DR-1 Generator Distribution Connected

| Assumptions and Fixed Inputs | | Value |
|---|---|---|
| Energy Balancing Service | Top Up rate ¢/kWh | 9.959 |
| Energy Balancing Service | [7]Spill rate ¢/kWh | 5.27 |
| Standby Services Tariff | GC = Generator Capacity (MW) | 1.0 |
| Standby Services Tariff | [8]CC = capacity contribution factor | 0.17 |
| Standby Services Tariff | Demand Charge per mo. Per kW $ | 5.37 |
| PR (Planning Reserve) | (NPCC planning criteria) | 20% |
| Average hours per month | =365*24/12 | 730 |
| System Ave. Loss Factor | (from NS Power OASIS site) | 2.28% |
| Distribution Losses | (from 2014 COSS - domestic dist losses: Feb) | 7.70% |
| RTT demand charge | Demand Charge per mo. Per kW $ | 5.37 |
| RTT energy charge | ¢/kWh | 3.309 |

**Assumptions:**

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes that the Generation facility is suitable sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]No Embedded Cost Recovery Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

**DR-1 Generator Distribution Connected**

Note: each scenario considered to occur in a different month

| | Scenario i) | Scenario ii) | Scenario iii) |
|---|---|---|---|
| Renewable Generator Capacity[10] | 1.0 | 1.0 | 1.0 |
| Hourly Generation (MW)[3] | 0.5 | 1.0 | 1.0 |
| Generation adjusted for losses[2] | 0.489 | 0.978 | 0.978 |
| Customer Load on Distribution Sub. A (MW)[3] | 1.0 | 0.5 | 1.0 |
| LRS Aggregate Load adjusted for distribution losses[2] | 1.077 | 0.539 | 1.077 |
| Number of Customers[12] | 431 | 215 | 431 |
| LRS Aggregate customer load (MWh) in the hour | 1.077 | 0.539 | 1.077 |
| Top Up MWh delivered by NS Power in the hour | 0.588 | 0.000 | 0.099 |
| Spill MWh received by NS Power in the hour | 0.000 | -0.439 | 0.000 |

1 EBS Charges

Note: EBS hourly Top-up and Spill quantities are determined at the delivery point from the transmission system

| | Scenario i) | Scenario ii) | Scenario iii) |
|---|---|---|---|
| Charges for Top Up MWh delivered by NS Power in the hour | $ 58.57 | $ - | $ 9.89 |
| Credits for Spill MWh received by NS Power in the hour | $ - | $ (23.15) | $ - |
| EBS Administration Charge applicable to the hour ($1053.03/730 hours) | $ 1.44 | $ 1.44 | $ 1.44 |
| **Total EBS** | **$ 60.02** | **$ (21.70)** | **$ 11.33** |

2 Standby Services Charges

| | | Scenario i) | Scenario ii) | Scenario iii) |
|---|---|---|---|---|
| | CMPFD[4,9] | 1.077 | 0.539 | 1.077 |
| (from Table in SS Tariff) | CMDAF[4] | 1.000 | 1.000 | 1.000 |
| | LWPFD | 1.077 | 0.539 | 1.077 |
| | CC*GC/(1+PR)[8] | 0.142 | 0.142 | 0.142 |
| | Min (LWPFD,CC*GC/(1+PR)) | 0.142 | 0.142 | 0.142 |
| | MSCD (MW) | 0.935 | 0.397 | 0.935 |
| | Standby Demand Charge applicable in the hour | $ 6.88 | $ 2.92 | $ 6.88 |
| | Standby Services Admin. Charge applicable to the hour ($1053.03/730 hours) | $ 1.44 | $ 1.44 | $ 1.44 |
| | **Total SS** | **$ 8.32** | **$ 4.36** | **$ 8.32** |

## DR-1 Generator Distribution Connected

| Assumptions and Fixed Inputs | | Value |
|---|---|---|
| Energy Balancing Service | Top Up rate ¢/kWh | 9.959 |
| Energy Balancing Service | [7]Spill rate ¢/kWh | 5.27 |
| Standby Services Tariff | GC = Generator Capacity (MW) | 1.0 |
| Standby Services Tariff | [8]CC = capacity contribution factor | 0.17 |
| Standby Services Tariff | Demand Charge per mo. Per kW $ | 5.37 |
| PR (Planning Reserve) | (NPCC planning criteria) | 20% |
| Average hours per month | =365*24/12 | 730 |
| System Ave. Loss Factor | (from NS Power OASIS site) | 2.28% |
| Distribution Losses | (from 2014 COSS - domestic dist losses: Feb) | 7.70% |
| RTT demand charge | Demand Charge per mo. Per kW $ | 5.37 |

**Assumptions:**

[1]Assumes each scenario considered to occur in a different month
[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%
[3]Assumes quantities as metered at the generator output and at the distribution load.
[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0
[5]Assume Distribution connected load is 100% Domestic class
[6] Includes all ancillary services
[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load
[8]Assumes renewable generator is a wind generator
[9]Assumes customer load as firm load with peak occurring coincident with system firm load
[10]Assumes that the Generation facility is suitable sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).
[11]No Embedded Cost Recovery Charges are included in these calculations
[12]Average Domestic Customer load is 2.5 kW (Winter example)

**3 Distribution Tariff Charges[5]**

| | | | Based on quantities as metered at the distribution level | | |
|---|---|---|---|---|---|
| Domestic | DT rate | 2.549 ¢/kWh | $ 25.49 | $ 12.75 | $ 25.49 |
| | Fixed Customer Charge/mo./customer[12] | $ 10.83 | $ 6.39 | $ 3.20 | $ 6.39 |
| | | Total DT | **$ 31.88** | **$ 15.94** | **$ 31.88** |

**4 Transmission Tariff Charges[6]**

| | | $/MW/Month | $/MW/hr | Based on LRS aggregate load in each Scenario | | |
|---|---|---|---|---|---|---|
| Scheduling/Sys Control | Sch 1 | $ 353.98 | $ 0.4849 | $ 0.52 | $ 0.26 | $ 0.52 |
| Reactive Supply/Voltage | Sch 2 | $ 182.76 | $ 0.2504 | $ 0.27 | $ 0.13 | $ 0.27 |
| Regulation | Sch 3 | $ 217.06 | $ 0.2973 | $ 0.32 | $ 0.16 | $ 0.32 |
| Load Following | Sch 3 | $ 776.85 | $ 1.0642 | $ 1.15 | $ 0.57 | $ 1.15 |
| Spinning reserve | Sch 5 | $ 166.58 | $ 0.2282 | $ 0.25 | $ 0.12 | $ 0.25 |
| Op reserve 10 min. | Sch 6 | $ 331.83 | $ 0.4546 | $ 0.49 | $ 0.24 | $ 0.49 |
| Op reserve 30 min. | Sch 6 | $ 281.23 | $ 0.3852 | $ 0.41 | $ 0.21 | $ 0.41 |
| Network Trans service | Sch 10 | $ 4,241.21 | $ 5.8099 | $ 6.26 | $ 3.13 | $ 6.26 |
| | | | Total OATT | **$ 9.67** | **$ 4.83** | **$ 9.67** |

**5 RTT, scenario**

| | | | |
|---|---|---|---|
| Displaced capacity (MW) | 0.142 | 0.142 | 0.142 |
| Demand element of charge | $ 1.04 | $ 1.04 | $ 1.04 |
| Displaced energy (MWh) | 0.489 | 0.539 | 0.978 |
| Energy element of charge | $ 16.18 | $ 17.82 | $ 32.35 |
| Total RTT | $ 17.22 | $ 18.86 | $ 33.39 |

**6 RtR charges / hr for scenario incl RTT**

| | | | |
|---|---|---|---|
| Energy Charges | $ 100.24 | $ 7.42 | $ 67.73 |
| Demand Charges | $ 17.59 | $ 8.79 | $ 17.59 |
| Customer / LRS Charges | $ 9.28 | $ 6.08 | $ 9.28 |
| **Total charges /hr for scenario** | **$ 127.10** | **$ 22.29** | **$ 94.60** |

**7 RtR charge / customer MWhr incl RTT**

| | | | |
|---|---|---|---|
| Energy Charges | $ 100.24 | $ 14.84 | $ 67.73 |
| Demand Charges | $ 17.59 | $ 17.59 | $ 17.59 |
| Customer / LRS Charges | $ 9.28 | $ 12.16 | $ 9.28 |
| **Total RtR Charges /MWh incl RTT** | **$ 127.10** | **$ 44.58** | **$ 94.60** |

## DR-2 Generator Transmission connected

**Assumptions and Fixed Inputs**

| | | Value |
|---|---|---|
| **Energy Balancing Service** | Top Up rate ¢/kWh | 9.959 |
| **Energy Balancing Service** | [7]Spill rate ¢/kWh | 5.27 |
| **Standby Services Tariff** | GC = Generator Capacity (MW) | 15 MW |
| **Standby Services Tariff** | [8]CC = capacity contribution factor | 0.17 |
| **Standby Services Tariff** | Demand Charge per mo. Per kW $ | 5.37 |
| **PR (Planning Reserve)** | (NPCC planning criteria) | 20% |
| **Average hours per month** | =365*24/12 | 730 |
| **System Ave. Loss Factor** | (from NS Power OASIS site) | 2.28% |
| **Distribution Losses** | (from 2014 COSS - domestic dist losses: Feb) | 7.70% |
| | | |
| **RTT demand charge** | Demand Charge per mo. Per kW $ | 5.37 |
| **RTT energy charge** | ¢/kWh | 3.309 |

**Assumptions:**

**[1]Assumes each scenario considered to occur in a different month**
**[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%**
**[3]Assumes quantities as metered at the generator output and at the distribution load.**
**[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0**
**[5]Assume Distribution connected load is 100% Domestic class**
**[6] Includes all ancillary services**
**[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load**
**[8]Assumes renewable generator is a wind generator**
**[9]Assumes customer load as firm load with peak occurring coincident with system firm load**
**[10]Assumes Generation facility is sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).**
**[11]No Embedded Cost Recovery Charges are included in these calculations**
**[12]Average Domestic Customer load is 2.5 kW (Winter example)**

| | DR-2 Generator Transmission connected | | |
|---|---|---|---|
| | Note: each scenario considered to occur in a different month | | |
| | Scenario i) | Scenario ii) | Scenario iii) |
| **Renewable Generator Capacity[10]** | 15.0 | 15.0 | 15.0 |
| **Hourly Generation Capacity (MW)[3]** | 15.0 | 10.0 | 15.0 |
| **Generation adjusted for losses to transmission/distribution interface[2]** | 14.67 | 9.78 | 14.67 |
| **Metered Customer Load - Distribution Sub. A (MW)[3]** | 5.0 | 1.0 | 1.0 |
| **Metered Customer Load - Distribution Sub. B (MW)[4]** | 5.0 | 5.0 | 5.0 |
| **Metered Customer Load - Distribution Sub. C (MW)[5]** | 5.0 | 5.0 | 1.0 |
| | | | |
| **LRS Aggregate customer load MWh in the hour** | 15.0 | 11.0 | 7.0 |
| **LRS Aggregate Load adjusted for distribution losses[2]** | 16.16 | 11.85 | 7.54 |
| **Number of Customers[12]** | 6462 | 4739 | 3016 |
| **Top Up MWh delivered by NS Power in the hour** | 1.49 | 2.07 | 0.00 |
| **Spill MWh received by NS Power in the hour** | 0.00 | 0.00 | -7.13 |

**1 EBS Charges**

**Note: EBS hourly Top-up and Spill quantities are determined at the delivery point from the transmission system**

| | Scenario i) | Scenario ii) | Scenario iii) |
|---|---|---|---|
| **Charges for Top Up MWh delivered by NS Power in the hour** | $ 148.33 | $ 206.14 | $ - |
| **Credits for Spill MWh received by NS Power in the hour** | $ - | $ - | $ (375.57) |
| **EBS Administration Charge applicable to the hour ($1053.03/730 hours)** | $ 1.44 | $ 1.44 | $ 1.44 |
| **Total EBS** | **$ 149.77** | **$ 207.59** | **$ (374.13)** |

**2 Standby Services Charges**

| | | Scenario i) | Scenario ii) | Scenario iii) |
|---|---|---|---|---|
| | **CMPFD[4,9]** | 16.16 | 11.85 | 7.54 |
| (from Table in SS Tariff) | **CMDAF[4]** | 1.0 | 1.0 | 1.0 |
| | **LWPFD** | 16.16 | 11.85 | 7.54 |
| | **CC*GC/(1+PR)[8]** | 2.13 | 2.13 | 2.13 |
| | **Min (LWPFD,CC*GC/(1+PR)** | 2.13 | 2.13 | 2.13 |
| | **MSCD (MW)** | 14.03 | 9.72 | 5.41 |

| | Scenario i) | Scenario ii) | Scenario iii) |
|---|---|---|---|
| **Standby Demand Charge applicable in the hour** | $ 103.21 | $ 71.52 | $ 39.83 |
| **Standby Services Administration Charge applicable to the hour ($1053.03/730 hours)** | $ 1.44 | $ 1.44 | $ 1.44 |
| **Total SS** | **$ 104.65** | **$ 72.96** | **$ 41.27** |

## DR-2 Generator Transmission connected

**Assumptions and Fixed Inputs**

| | | Value |
|---|---|---|
| **Energy Balancing Service** | Top Up rate ¢/kWh | 9.959 |
| **Energy Balancing Service** | [7]Spill rate ¢/kWh | 5.27 |
| **Standby Services Tariff** | GC = Generator Capacity (MW) | 15 MW |
| **Standby Services Tariff** | [8]CC = capacity contribution factor | 0.17 |
| **Standby Services Tariff** | Demand Charge per mo. Per kW $ | 5.37 |
| **PR (Planning Reserve)** | (NPCC planning criteria) | 20% |
| **Average hours per month** | =365*24/12 | 730 |
| **System Ave. Loss Factor** | (from NS Power OASIS site) | 2.28% |
| **Distribution Losses** | (from 2014 COSS - domestic dist losses: Feb) | 7.70% |
| **RTT demand charge** | Demand Charge per mo. Per kW $ | 5.37 |

**Assumptions:**

**[1]Assumes each scenario considered to occur in a different month**

**[2]Transmission losses assumed at 2.28% and Dist. losses assumed at 7.7%**

**[3]Assumes quantities as metered at the generator output and at the distribution load.**

**[4]Assume load as metered is a peak for the month and occurs in a winter month (Jan/Feb/Dec), CMDAF= 1.0**

**[5]Assume Distribution connected load is 100% Domestic class**

**[6] Includes all ancillary services**

**[7]Assumes annual excess spill quantity in the range of 0%-10% of annual LRS load**

**[8]Assumes renewable generator is a wind generator**

**[9]Assumes customer load as firm load with peak occurring coincident with system firm load**

**[10]Assumes Generation facility is sized to meet the contracted amount of annual LRS RtR energy, i.e. GC=MSC (Maximum Spill Capacity).**

**[11]No Embedded Cost Recovery Charges are included in these calculations**

**[12]Average Domestic Customer load is 2.5 kW (Winter example)**

**3 Distribution Tariff Charges[5]**

| | | | | Based on quantities as metered at the distribution level | | |
|---|---|---|---|---|---|---|
| Domestic | DT rate | 2.549 ¢/kWh | | $ 382.35 | $ 280.39 | $ 178.43 |
| | Fixed Customer Charge/mo./customer[12] | $ 10.83 | | $ 95.868 | $ 95.868 | $ 95.868 |
| | | | **Total DT** | **$ 478.22** | **$ 376.26** | **$ 274.30** |

**4 Transmission Tariff Charges[6]**

| | | $/MW/Month | $/MW/hr | | Based on LRS aggregate load in each Scenario | | |
|---|---|---|---|---|---|---|---|
| Scheduling/Sys Control | Sch 1 | $ 353.98 | $ 0.4849 | | $ 7.83 | $ 5.74 | $ 3.66 |
| Reactive Supply/Voltage | Sch 2 | $ 182.76 | $ 0.2504 | | $ 4.04 | $ 2.97 | $ 1.89 |
| Regulation | Sch 3 | $ 217.06 | $ 0.2973 | | $ 4.80 | $ 3.52 | $ 2.24 |
| Load Following | Sch 3 | $ 776.85 | $ 1.0642 | | $ 17.19 | $ 12.61 | $ 8.02 |
| Spinning reserve | Sch 5 | $ 166.58 | $ 0.2282 | | $ 3.69 | $ 2.70 | $ 1.72 |
| Op reserve 10 min. | Sch 6 | $ 331.83 | $ 0.4546 | | $ 7.34 | $ 5.39 | $ 3.43 |
| Op reserve 30 min. | Sch 6 | $ 281.23 | $ 0.3852 | | $ 6.22 | $ 4.56 | $ 2.90 |
| Network Transmission service | Sch 10 | $ 4,241.21 | $ 5.8099 | | $ 93.86 | $ 68.83 | $ 43.80 |
| | | | | **Total OATT** | **$ 144.99** | **$ 106.32** | **$ 67.66** |

**5 RTT, scenario**

| | | | | |
|---|---|---|---|---|
| Displaced capacity (MW) | | 2.13 | 2.13 | 2.13 |
| Demand element of charge | | $ 15.63 | $ 15.63 | $ 15.63 |
| Displaced energy (MWh) | | 14.67 | 9.78 | 7.54 |
| Energy element of charge | | $ 485.29 | $ 323.52 | $ 249.47 |
| | **Total RTT** | $ 500.92 | $ 339.16 | $ 265.10 |

**6 RtR charges / hr for scenario incl RTT**

| | | | |
|---|---|---|---|
| Energy Charges | $ 1,015.96 | $ 810.06 | $ 52.32 |
| Demand Charges | $ 263.82 | $ 193.47 | $ 123.12 |
| Customer / LRS Charges | $ 98.75 | $ 98.75 | $ 98.75 |
| **Total charges /hr for scenario** | **$ 1,378.54** | **$ 1,102.28** | **$ 274.19** |

**7 RtR charge / customer MWhr incl RTT**

| | | | |
|---|---|---|---|
| Energy Charges | $ 67.73 | $ 73.64 | $ 7.47 |
| Demand Charges | $ 17.59 | $ 17.59 | $ 17.59 |
| Customer / LRS Charges | $ 6.58 | $ 8.98 | $ 14.11 |
| **Total RtR Charges /MWh incl RTT** | $ 91.90 | $ 100.21 | $ 39.17 |

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**Request IR-2:**

**Reference: Hourly Marginal Costs**

**SWEB Requests that NSPI provide an hourly breakdown of Marginal Cost over the most recent year available, and a forecast of the trends expected in Marginal Cost by NS Power over the next 5 years.**

Response IR-2:

The requested analysis was not completed as part of this Application. Please refer to **CA IR-20**.

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**Request IR-3:**

**Reference: Time-of-Day and Seasonal Considerations for Energy Balancing Service Tariff**

**SWEB requests that time-of-day and seasonal tariffs be considered for the Energy Balancing Service Tariff. As indicated as possible by NSPI and SWEB during the September 11, 2015 Technical Conference, SWEB requests the provision of these tariffs for information purposes only, at this stage.**

**For clarity, SWEB does not request that NSPI change the existing tariff to include seasonal or time-of-day considerations, as of yet; but instead is requesting this data for informational and analytical purposes.**

**(a) SWEB requests the below tariff components are considered for this change, as outlined in Section 9.1 of the NSPI RtR Application of September 1, 2015:**

- **(i) Annually Adjusted Fuel Cost (currently proposed as fixed at 6.650 ¢/kWh)**
- **(ii) Fixed Cost for fixed energy-related generation costs (currently proposed as fixedat 3.309 ¢/kWh)**
- **(iii) Energy Spill Credit (currently proposed as fixed at 5.270 ¢/kWh)**

**(b) SWEB requests that the tariffs be changed from fixed values to Annually Adjusted, pre-schedule rate categories based on:**

- **(i) Month**
- **(ii) Weekend/Weekday**
- **(iii) Hour-of-Day [On-Peak/Off –Peak]**

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Response IR-3:

NS Power gave consideration to such a tariff structure during the design phase. Please refer to **CA IR-8** for further discussion.

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**Request IR-4:**

**Reference: Anticipated Thresholds for Changes to Tariffs**

**A number of Tariffs and charges envisioned within the September 1, 2015 Application include an Annually Adjusted Rates framework (As also discussed in Section 2.4 of the Application).**

**SWEB requests that Nova Scotia Power Inc. outline the anticipated thresholds for future, annual changes to these tariffs (shown as either +/- percentage bands or otherwise). SWEB also request that brief explanations of the reasoning for the changes to these tariffs; such as FAM considerations, LRS participation, customer participation, etc.**

**SWEB understands that any values provided under this Information Request will be for discussion and analysis purposes only, and will not be considered as part of the framework of Nova Scotia Power Inc.'s formal Application to the UARB.**

Response IR-4:

NS Power's evidence provides as follows:

> In addition to the revisions incorporated within the anticipated Compliance filing, the Company proposes that the rates in the RtR tariffs be adjusted annually within the Annually Adjusted Rates framework based on forecast fuel costs for the following year.[1]

The Annually Adjusted Rates (AAR) framework does not provide for any thresholds or limitations to changes in rates. AAR foundations are predicated on prospective changes in incremental fuel and administrative costs. These are optional rates which have been developed

[1] Application, page 18, lines 24 – 26.

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for customers who have specific operating capabilities and cost characteristics, such as access to self-generation, process storage and ability to shift or interrupt their load. These capabilities and characteristics put them in a unique position to take advantage of marginal cost based rates. The application of marginal cost based rates in such circumstances is appropriate. Due to higher volatility of incremental costs these rates are adjusted on an annual basis to minimize risks of cost transfers between AAR customers and base cost rate customers.

**Request IR-5:**

**Reference: Third-Party Provision of Energy Balancing Services**

**Nova Scotia Power Inc. confirmed, during the September 11, 2015 Technical Conference, that third-party provision of Energy Balancing Services (in whole or in part) were not considered under the September 1, 2015 Application to the UARB.**

**SWEB Development Inc. would like to inquire as to why third-party provision of Energy Balancing Services, in whole or in part, was not considered in the September 1, 2015 Application to the UARB; and what possibilities there are for this third-party service in the future.**

Response IR-5:

Third party supply of top-up was considered in tariff design, but was not incorporated into the proposed tariff for the reasons set out in Application **Appendix 16, section 5.3.3.**

Three theoretical configurations for supply of top-up are described in that section. Recognising interaction with other tariffs, particularly the Renewable to Retail Market Transition Tariff, as well as compliance obligations, none was considered to be economically viable and thus to warrant the added complexity of tariffs and processes to be included.

**Request IR-6:**

**Reference: COSS Clarifications**

**Exhibit 13C takes total demand related costs from the COSS and divides by total demand requirements.**

**SWEB understands these values to be: $121M/1881MW**

**However, the stated $121M is based on a total generation capacity of 2,453MW (from the related website). SWEB notes that is seems that this seems to have almost 600MW of excess capacity. It seems that either only the costs associated with the 1881MW needed should be carried, or that the rate should be costs divided by 2,453MW.**

**SWEB requests further clarification on this aspect of the COSS considerations.**

Response IR-6:

NS Power's approach to calculation of the demand charge under the Standby Service Tariff aligns with industry ratemaking practice. It reflects the cost of installed capacity designed to meet ratepayers' requirement for demand services. The installed capacity of 2,453 MW includes a long-term 20% planning reserve and operating reserves required by the Northeast Power Coordinating Council (NPCC). The planning reserves are in place to ensure adequate reliability of generation services to NS Power's firm service customers, while operating reserves serve the purpose of covering the largest single generation contingency in the Maritimes Area. Further, the installed capacity includes the capacity of non-dispatchable generation of which a smaller portion counts towards the 20% planning reserve and none towards operating reserves.

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**Request IR-7:**

**Reference: Technical Inquiries (i)**

**(a) Under the assumptions included in Appendix 13B of the September 1, 2015 Application, and other shown calculations, it is assumed that four (4) LRSs will be licensed and active under the RtR program.**

**SWEB Development Inc. would like to inquire what changes to the overhead and administration costs would be expected to change with different values of LRS participation, or if there is a simple assumption that there is one FTE needed for each group of four (4) LRSs.**

**(b) The Plexus model for Appendix 13B assumes a flat 25MW decrement. SWEB Development Inc. would like to request considerations that include generation sizing's of:**

**(i) 5MW**
**(ii) 10 MW**
**(iii) 100 MW**

**(c) Under Appendix 13B, and generally speaking under the assumed RtR tariff framework, SWEB Development Inc. would like to inquire as to:**

**(i) Which generation sources are assumed?**

**(ii) When wind energy generation is assumed, what capacity factors and load shapes as assumed?**

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**(d) Under Appendix 13B, and generally speaking under the assumed RtR tariff framework, SWEB Development Inc. would like to inquire as to:**

**(i) The customer load shapes assumed for Domestic, Commercial and Industrial customers for the purposes of compiling RtR tariffs.**

Response IR-7:

(a) The proposed approach to the recovery of administrative costs is based on the cost estimates filed in the Wholesale Market Backup/Top-up and Wholesale Market Non-Dispatchable Spill Tariff applications for 2015. The Company assumed in the 2015 applications that one Full-Time-Equivalent (FTE) employee would be sufficient to provide admin services to four wholesale customers and one energy supplier. The Company determined that one additional FTE should be sufficient to meet demand for admin services of four LRS taking top-up, spill and standby services. The Company has not made a determination whether one FTE would be required per four additional LRSs if more LRSs were to enter the RtR market.

(b) The requested analysis was not completed for this Application.

Please note that the Company used results of 50 MW block Plexus runs in **Appendix 13B** and not the 25 MW blocks as indicated in the response to Multeese DR-25. Going forward, for the purposes of the Annually Adjusted Rate setting process, the Company proposes to apply calculations based on the 25 MW block.

(c) (i) The Company performed Plexos runs based on two separate hourly load shape profiles.

(a) wind generation and
(b) flat decrement of 50 MW across all hours.

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Please refer to **SBA IR-8** for the simulated results of these runs.

(ii) The wind shape was based on a 50 MW wind profile with a 33% capacity factor.

(d) The customer load shape used in Plexos is an amalgamated load shape that does not differentiate between customer types. The load used for the RtR Plexos runs was the IRP Mid DSM load shape (from the preferred resource plan).