Alberta Utilities Commission

Direct Energy Regulated Services

Acknowledgment of the Filing of Changes in the Forecast Load Methodology and Approval of Revisions to the 2020-2022 Energy Price Setting Plan

June 14, 2021

Alberta Utilities Commission
Decision 26545-D01-2021
Direct Energy Regulated Services
Acknowledgment of the Filing of Changes in the Forecast Load Methodology and
Approval of Revisions to the 2020-2022 Energy Price Setting Plan
Proceeding 26545

June 14, 2021

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The Commission may, within 60 days of the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

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Calgary, Alberta

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1 Decision summary

1. In this decision, the Alberta Utilities Commission considers whether to approve a request from Direct Energy Regulated Services (DERS) for changes in DERS' forecast load methodology included in its 2020-2022 energy price setting plan (the 2020-2022 EPSP (Index)). If the forecast load methodology changes are accepted by the Commission, approval of revisions to the 2020-2022 EPSP (Index) are necessary to incorporate the changes.

2. For the reasons set out in this decision, the Commission acknowledges the filing of the changes in the forecast load methodology and approves the revisions to the 2020-2022 EPSP (Index) as filed.

2 Background

3. DERS is a business unit of Direct Energy Marketing Limited. DERS is a regulated rate option (RRO) provider and performs the electricity regulated rate tariff functions in the distribution service territory of ATCO Electric Ltd. DERS was appointed by ATCO Electric as the RRO provider under Section 104 of the *Electric Utilities Act*.

4. As an RRO provider, DERS is required to file monthly electric energy rates with the Commission. These monthly electric energy rates are determined pursuant to the *Electric Utilities Act*, in accordance with the *Regulated Rate Option Regulation* and the EPSP approved by the Commission. DERS' approved EPSP establishes the pricing of electricity for RRO customers in the distribution service territory of ATCO Electric.

5. In Decision 25818-D01-2021,[1] the Commission approved the 2020-2022 EPSP (Index). The 2020-2022 EPSP (Index) was reached through a negotiated settlement process, which resulted in a negotiated settlement agreement (NSA). The electric energy rates for July 2021 will be the first month that rates are determined in accordance with the 2020-2022 EPSP (Index).

6. Schedule C of the 2020-2022 EPSP (Index) sets out the steps to determine DERS' monthly RRO load forecasts. Section D of Schedule C describes the approval process for any forecast load methodology improvements that DERS identifies during the term of the 2020-2022 EPSP (Index), as follows:

[1] Decision 25818-D01-2021: Direct Energy Regulated Services, 2020-2022 Energy Price Setting Plan – Negotiated Settlement Agreement, Proceeding 25818, February 25, 2021.

1. Any Forecast Load methodology improvements identified during the term of the EPSP will be filed for acknowledgement with the Commission prior to implementation. In the acknowledgement filing, DERS will include:

   i. An explanation of the change to the methodology or adjustment to the inputs to the forecast;
   ii. Supporting analysis for the change to the methodology or adjustment to the inputs to the forecast; and
   iii. A schedule that shows the history of all the changes to the methodology and changes to the inputs to the forecast.[2]

7. On May 18, 2021, DERS filed an application to change its forecast load methodology, in accordance with Section D of Schedule C of the 2020-2022 EPSP (Index). The application also included proposed revisions to the 2020-2022 EPSP (Index) that are necessary to incorporate the proposed changes to the forecast load methodology. DERS requested that a confidentiality ruling for certain confidential material in Proceeding 25818 be continued for the current proceeding, in order for DERS to file the redacted and confidential versions of the amended 2020-2022 EPSP (Index) on the record of the current proceeding.

8. On May 19, 2021, the Commission issued a notice of application requiring any party that wished to intervene in the proceeding to file a statement of intent to participate (SIP) by May 28, 2021.

9. In the application, DERS submitted that as approved, the 2020-2022 EPSP (Index) permits forecast methodology improvements to be implemented through acknowledgment filings. DERS added that it had provided both the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA) with a courtesy copy of the application in advance of filing it with the Commission.[3] The CCA and the UCA were therefore provided both with a copy of the application and with notice of the filed application issued in this proceeding.

10. No SIPs were filed in support of, or objecting to, the application.

11. On May 28, 2021, the Commission issued a ruling[4] granting DERS' request to continue the confidential treatment granted to certain material in the 2020-2022 EPSP (Index) in Proceeding 25818, to the current proceeding. On May 28, 2021, DERS filed public (redacted) and confidential copies of the amended 2020-2022 EPSP (Index). Blacklined and clean copies of both documents were filed.[5]

12. The Commission considers that the close of record for this proceeding was May 28, 2021.

13. In reaching the determinations set out within this decision, the Commission has considered all relevant materials on the public record of this proceeding as well as the

[2] Decision 25818-D01-2021, Appendix 4 – 2020-2022 EPSP (Index), page 14.
[3] Exhibit 26545-X0001, pages 5-6.
[4] Exhibit 26545-X0005.
[5] The blacklined copy of the amended public (redacted) 2020-2022 EPSP (Index) is in Exhibit 26545-X0006. The clean copy of the amended public (redacted) 2020-2022 EPSP (Index) is in Exhibit 26545-X0007. The blacklined copy of the amended confidential 2020-2022 EPSP (Index) is in confidential Exhibit 26545-X0006-C. The clean copy of the amended confidential 2020-2022 EPSP (Index) is in confidential Exhibit 26545-X0007-C.

confidential filings. A separate confidential decision will be issued on the Commission's eFiling System under the "Confidential" tab in this proceeding.

3 Changes in DERS' forecast load methodology in the 2020-2022 EPSP (Index)

14. DERS indicated that the change to the forecast load methodology involves amending the determination of the line loss factors (LLFs) for every customer rate class. The 2020-2022 EPSP (Index) defines the LLFs as being "the Distribution Line Losses by Rate Class that are most recently approved by the AUC for the ATCO Electric distribution service area for each rate class, expressed as a percentage of customers' usage for each Rate Class."[6]

15. The LLFs are one of the components of the distribution line loss (DLL) percentages for each rate class. The DLL percentages are used in the calculation of the monthly forecast total load and corresponding hedge target procurement volumes. The percentages are also used in the calculation of the electric energy rates to gross-up the base energy charge, the commodity risk compensation and the Alberta Electric System Operator trading charge components.

16. DERS indicated that it discovered that ATCO Electric's average secondary distribution system line losses have increased from approximately five per cent to six per cent.[7] It described this increase as an unforeseen consequence of an approved change to ATCO Electric's price schedules, effective August 1, 2020,[8] in Decision 24747-D01-2020.[9] DERS stated that since August 2020, the increase in LLFs resulting from the approval in Decision 24747-D01-2020 has, and will continue to, cause a persistent forecast error for its monthly RRO load forecasts.[10] DERS noted that despite the increase in ATCO Electric's average secondary distribution system line losses, there has been no corresponding adjustment to the approved LLFs for ATCO Electric's secondary distribution system, and these approved ATCO Electric LLFs are used by DERS as part of determining its monthly RRO load forecast, consistent with Section A(4)(b) of Schedule C of the 2020-2022 EPSP (Index).[11]

17. DERS provided the following information about what has caused the increase in ATCO Electric's average secondary distribution system line losses since August 2020:

> As part of ATCO's 2019 Distribution Tariff Phase II Application (Proceeding ID 24747), ATCO proposed the elimination of Option H(b) from its price schedules, as that type of metering configuration was no longer compliant with Measurement Canada standards.[12]
>
> The Commission approved this proposal, effective August 2020, in AUC Decision 24747-D01-2020.…[13]
>
> …

[6] Decision 25818-D01-2021, Appendix 4 – 2020-2022 EPSP (Index), page 13.
[7] Exhibit 26545-X0001, page 1.
[8] Exhibit 26545-X0001, pages 1-2.
[9] Decision 24747-D01-2020: ATCO Electric Ltd., 2019 Distribution Tariff Phase II Application, Proceeding 24747, April 30, 2020.
[10] Exhibit 26545-X0001, page 1.
[11] Exhibit 26545-X0001, page 2.
[12] Exhibit 26545-X0001, page 2.
[13] Exhibit 26545-X0001, page 2.

> This change had an unforeseen knock-on effect for how ATCO calculates its distribution losses. Based on DERS' discussions with ATCO, DERS understands that ATCO calculates its total distribution losses, which it then separates into primary and secondary distribution losses. This separation is based on whether the site takes service directly from the primary distribution system or from the secondary distribution system. ATCO calculates the total distribution losses for each service level (primary and secondary) and allocates these losses to retailers based on the customers they serve. DERS' RRO customers are served by the secondary distribution system, and are therefore allocated secondary distribution losses by ATCO.[14] [footnote removed]
>
> Option H(b) customers were formerly classified as "secondary" customers to which secondary distribution losses were allocated. However, as a result of Option H(b) being eliminated, those customers were reclassified as "primary" customers to which primary distribution losses are allocated (which are significantly lower than secondary distribution losses). The net effect is that there are fewer secondary customers amongst whom ATCO's secondary distribution losses are allocated, resulting in higher distribution line loss costs for secondary customers (including DERS' RRO customers) subsequent to ATCO's elimination of Option H(b).[15]

18. DERS stated that ATCO Electric communicated that it will not be filing an application to update its LLFs before 2022 and it is not known when updated ATCO Electric LLFs may be approved by the Commission. As a result, DERS reviewed its forecast load methodology and proffered that the use of historical settlement data is a clear improvement to determine the LLFs for the 2020-2022 EPSP (Index).[16]

19. DERS proposed to change the forecast load methodology employed in the 2020-2022 EPSP (Index) through the following amendments:

- Section 1 of Schedule A of the 2020-2022 (Index) EPSP is amended, by deleting the following:

  > Line Loss Factor or LLFRC means the distribution line losses by Rate Class that are most recently approved by the AUC for the ATCO Electric distribution service area by rate class, expressed as a percentage of customers' usage within the Rate Class;

- Section 1 of Schedule A of the 2020-2022 (Index) EPSP is amended, by adding the following:

  > Line Loss Factor or LLFRC means the distribution line losses by Rate Class which will be determined by calculating the monthly line loss volumes as a percent of monthly metered volumes using the most recent six months of Final Settlement data for the Rate Class and taking the average of the monthly percentages.

14 Exhibit 26545-X0001, page 2.
15 Exhibit 26545-X0001, page 3.
16 Exhibit 26545-X0001, page 4.

- Section A(4)(b) of Schedule C of the 2020-2022 (Index) EPSP is amended, by deleting the following:

> The Line Loss Factor (LLFRC) means the Distribution Line Losses by Rate Class that are most recently approved by the AUC for the ATCO Electric distribution service area for each rate class, expressed as a percentage of customers' usage for each Rate Class.

- Section A(4)(b) of Schedule C of the 2020-2022 (Index) EPSP is amended, by adding the following:

> Line Loss Factor or LLFRC means the distribution line losses by Rate Class which will be determined by calculating the monthly line loss volumes as a percent of monthly metered volumes using the most recent six months of Final Settlement data for the Rate Class and taking the average of the monthly percentages.[17]

20. In Disposition 26463-D01-2021,[18] the Commission acknowledged a similar change to the load forecasting methodology included in DERS' 2018-2020 EPSP and approved similar amendments to the 2018-2020 EPSP. The Commission notes that the reasons DERS provided for the change to the 2018-2020 EPSP are the same reasons provided in this application, in that a change to the load forecasting methodology and the LLFs is required because of the Commission approved elimination of Option H(b) from ATCO Electric's price schedules.

21. The Commission agrees with DERS that Section D of Schedule C of the 2020-2022 EPSP (Index) permits DERS to file forecast load methodology improvements for acknowledgment by the Commission prior to the implementation of the change. On review of the DERS explanation and analysis in support of a load forecast methodology change as required by Section D of Schedule C, the Commission finds that the proposed amendment to the 2020-2022 EPSP (Index) is an improvement to the forecast load methodology, and will result in more accurate monthly electric energy rates than would be the case if DERS continued to use the currently approved forecast load methodology. The Commission finds that the use of the approved LLFs as set out in the 2020-2022 EPSP (Index) does not reflect that the actual LLFs have changed significantly, whereas the proposed change to the determination of the LLFs to be included in the amended 2020-2022 EPSP (Index) does reflect the change in actual LLFs.

22. The Commission considers that to allow for the implementation of forecast load methodology improvements on a timely basis is contemplated in the specific provision in Section D of Schedule C in the 2020-2022 EPSP (Index), which was previously approved by the Commission, and the use of Section D of Schedule C to adjust the LLF is an efficient means to process the change.

23. Based on the findings and consideration set out above, and consistent with the Commission's previous findings in Disposition 26463-D01-2021, the Commission accepts the filing for acknowledgment with respect to the 2020-2022 EPSP (Index). Having acknowledged

17 Exhibit 26545-X0001, pages 4-5.
18 Disposition 26463-D01-2021: Direct Energy Regulated Services, Acknowledgment of the filing of changes in the forecast load methodology and approval of revisions to the 2018-2020 energy price setting plan, Proceeding 26463, April 21, 2021.

DERS' filing for the improvement to the forecast load methodology, the Commission therefore approves the revisions to the 2020-2022 EPSP (Index), as set out in paragraph 19 above. The approved, public, redacted version of the amended 2020-2022 EPSP (Index) is attached as Appendix 3 to this decision.

4 Other matters

24. Appendix F of the NSA approved in Decision 25818-D01-2021 is the illustrative rate book, which was filed as Exhibit 25818-X0116.01. The inputs and calculations required to determine the monthly electric energy rates that result from the 2020-2022 EPSP (Index) are outlined in the illustrative rate book. The Commission will use the illustrative rate book as part of its review and acknowledgment of DERS' monthly electric energy charges filings under the 2020-2022 EPSP (Index), which will commence with the filing of the electric energy charges for July 2021.

25. As a result of this decision, DERS will be required to revise the illustrative rate book to incorporate the amendments to the 2020-2022 EPSP (Index) approved by the Commission. Accordingly, the Commission directs DERS to file, as post-disposition documents in Proceeding 26545, the revised illustrative rate book, and a letter that includes details on which parts of the illustrative rate book have been revised, by no later than **4 p.m. on Monday, June 21, 2021.**

5 Order

26. It is hereby ordered that:

(1) Direct Energy Regulated Services amended 2020-2022 Energy Price Setting Plan (Index) is approved as filed.

Dated on June 14, 2021.

Alberta Utilities Commission

(original signed by)

Kristi Sebalj
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
Direct Energy Regulated Services (DERS)

Alberta Utilities Commission Commission panel K. Sebalj, Commission Member Commission staff A. Sabo (Commission counsel) D. Mitchell

Appendix 2 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. As a result of this decision, DERS will be required to revise the illustrative rate book to incorporate the amendments to the 2020-2022 EPSP (Index) approved by the Commission. Accordingly, the Commission directs DERS to file, as post-disposition documents in Proceeding 26545, the revised illustrative rate book, and a letter that includes details on which parts of the illustrative rate book have been revised, by no later than **4 p.m. on Monday, June 21, 2021.** .... paragraph 25

Appendix 3 – Amended 2020-2022 EPSP (Index) - redacted

(return to text)

Appendix 3 -
Amended 2020-2022

(consists of 32 pages)

DIRECT ENERGY REGULATED SERVICES

2020-2022 ENERGY PRICE SETTING PLAN (Index)

1. Definitions

Capitalized terms used in this Energy Price Setting Plan that are not otherwise defined herein, have the respective meanings ascribed to them in Schedule "A".

2. RRO Energy Charge

The RRO Energy Charge applicable to each Rate Class for the term of the EPSP to be included in the Company's RRT Price Schedules will be determined in accordance with Schedule "F". The various components making up the RRO Energy Charge will be determined as follows:

(a) Base Energy Charge

Prior to the first day of the Allowable Price Implementation Period for each Month, the Company will complete an initial Forecast Load for the RRO Customers for the Month. The Forecast Load will be prepared for each Month, and then updated for that Month during the Allowable Price Implementation Period, as described in Schedule "C".

The Energy Portfolio to be acquired by the Company for each Month will be determined in accordance with Schedule "D". The Company will acquire the Energy Portfolio using the Energy Acquisition Process set out in Schedule "B" and Confidential Schedule "E" to the EPSP.

Any load not procured through the Energy Acquisition Process under the EPSP will be supplied in accordance with the Backstop Methodology as provided for in Confidential Schedule "E" to the EPSP.

The Base Energy Charge component of the RRO Energy Charge by Rate Class for the Company's RRO Tariff for each Month over the term of the EPSP will be determined as described in Schedule "B" and Schedule "F" to the EPSP.

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(b) Energy Return Margin

The Energy Return Margin will be set at an after tax rate of $2.83/MWh, which shall be grossed up for taxes by applying the Effective Tax Rate.

(c) Cost Recovery Items

The Company will include in the RRO Energy Charge the additional items listed in Section C of Schedule "F". These items include NGX Collateral Costs and Counterparties Collateral Costs, NGX Trading Charges and Transaction Fees, AESO Trading Charges, AESO Collateral Costs, External EPSP Development and Regulatory Costs, RAM charges, and Uplift Charges calculated as shown in Section C of Schedule "F".

3. Filing of Energy Charge with AUC

In accordance with Section 12 of the RRO Regulation, DERS will file with the AUC for acknowledgement before the beginning of each Month, the RRO Energy Charge for each Rate Class for the Month, and the supporting calculations, determined in accordance with the formulas set out in the Energy Charge schedule (Schedule "F").

4. Code of Conduct

Access to commercially sensitive information in connection with the EPSP will be governed by the EPSP Code of Conduct set out in Schedule "G" and the Procurement Conduct Agreement set out in Appendix "G.1" to the EPSP.

5. Adjustment to the Protocol for Procurement Process

DERS will monitor market developments or trends that might have a material impact on the competitiveness of the Energy Acquisition Process. In the event that an adjustment is required to ensure the Energy Acquisition Process is competitive, DERS will file an adjustment with the AUC for acknowledgement prior to implementation.

6. Expiry Date

The expiry date of this EPSP is December 31, 2022.

7. Change in Law

In the event of any material change in applicable law or in policies or rules having the effect of law (including regulations, ministerial orders, AUC decisions, orders, guidelines, directives, or AUC or ISO [Independent System Operator] Rules) as a result of which additional material costs or benefits not provided for in the EPSP are incurred by DERS in its performance of the EPSP, a person directly and materially harmed or prejudiced by the change in the context of the operation of the EPSP may apply to the Commission for an order re-opening and modifying the EPSP to the extent required to address the change. An application made under this section must include, at a minimum, a detailed description of the change giving rise to the re-opening request, the direct and material harm or prejudice that the person believes will be suffered if the EPSP is not re-opened, and the specific modifications to the EPSP that the person requests that the Commission approve to address the change. For greater certainty, an application to re-open under this section will not be considered to be an application for review and variance and will not be subject to the requirements of AUC Rule 016 (*Review of Commission Decisions*) or any successor or replacement rule.

Schedule "A"
to DERS' EPSP

DEFINITIONS

1. Definitions

In the EPSP,

7x16 Peak Volume or **Peak Volume** or **7x16 Peak Product** or **Peak Product** means the volumes in MW for an electrical energy product for the hours HE08 to HE23, Monday through Sunday inclusive;

7x16 Peak Volume Block means 5MW of 7x16 Peak Product;

7x24 Base Volume or **Base Volume** or **7x24 Base Product** or **Base Product** means the volumes in MW for an electrical energy product for all hours in a day, Monday through Sunday inclusive;

7x24 Base Volume Block means 5 MW of 7x24 Base Product;

AESO means the Alberta Electric System Operator;

AESO Collateral Costs or **AESOCC** means the costs incurred for posting financial security with the AESO for a Month determined in accordance with Section C.2 of Schedule "F";

AESO Metered Volumes Report reports the hourly settlement volumes of pool participants according to asset id;

AESO Trading Charges or **AESOTC** means the current charges set by the AESO from time to time for transacting energy through the power pool;

Allowable Price Implementation Period or **APIP** means the period beginning up to 120 calendar days prior to the 1st day of the Month and ending 6 Business Days prior to the 1st day of the Month;

AUC or **Commission** means the Alberta Utilities Commission;

Backstop Methodology is detailed in Confidential Schedule "E";

Base Energy Charge by Rate Class or **BEC_{RC}** is the Energy Price in $/MWh of the Energy Portfolio for a Rate Class for a Month;

Base Product means an agreement to supply power during a Base Period at a specified price;

Base Period means the period from 00:00 hours to 24:00 hours Monday through Sunday inclusive;

Business Day means a day, which is not a Saturday, Sunday or a statutory holiday in the Province of Alberta, and "day" means any calendar day;

Commodity Risk Compensation or **CRC** is the amount as set out in Section D of Schedule "F";

Company means DIRECT ENERGY REGULATED SERVICES;

Counterparties Collateral Costs or **CCC** means credit costs that are in addition to any NGX Collateral Costs and AESO Collateral Costs, and include: (1) placement costs for having a sufficient credit facility in place to meet the total financial security requirements of the AESO and the NGX; and (2) standby (undrawn) credit costs associated with differences between the estimated credit facility and the estimated posted (drawn) financial security requirements;

Daily Target Price is the daily price calculated by DERS in accordance with Confidential Schedule "E";

DLL means the Distribution Line Loss factor and the forecast Unaccounted for Energy for the Rate Class as determined in Schedule "C" and is expressed as a percentage of customers' usage;

DEML means DIRECT ENERGY MARKETING LIMITED;

Derived Off Peak Procurement Price is the price DERS paid for energy in the Off-Peak Period that is derived from the Peak and Flat Block Procurement Prices;

DERS means DIRECT ENERGY REGULATED SERVICES a business unit of DEML;

EEA means EPCOR Energy Alberta GP Inc;

EEA Flat Price is the "Average Flat Price" from the EEA Monthly RRO Filing;

EEA Full-Load Price is the "Average Full-Load Price" from the EEA Monthly RRO Filing;

EEA Monthly RRO Filing is the EPCOR Energy Alberta GP Inc. Regulated Rate Option Acknowledgment Filing for Energy Charges that is submitted by EEA on the fifth last Business Day of each month;

EC_{RC} means the Energy Charge applicable to a Rate Class;

Effective Tax Rate means the combined Federal and Provincial tax rates expected to be in effect for a month to be applied to the Energy Return Margin by dividing the after-tax Energy Return Margin by one minus the combined Federal and Provincial Tax Rates;

Energy Acquisition Process means the process to procure Energy Product, as described in Schedule "B" to the EPSP;

Energy Charge or **RRO Energy Charge** or **RRO Energy Price** means the $/MWh amount applicable under the Company's RRO Tariff to a Rate Class for a Month as determined under Schedule "F";

Energy Portfolio means the Hedge Volumes acquired for a Month by way of the Energy Price Setting Process;

Energy Price means the price for electrical energy in $/MWh;

Energy Price Setting Plan or **EPSP** means the document entitled "2020-2022 Energy Price Setting Plan (Index)" and all attachments, schedules and appendices thereto including Schedule "A" – Definitions; Schedule "B" – Energy Price Setting Process; Schedule "C" – Forecast Load Methodology; Schedule "D" – Energy Portfolio Hedge Volume Determination Methodology; Confidential Schedule "E" – Protocol for Procurement; Schedule "F" – Energy Charge Applicable for Each Month During the Plan Term; Schedule "G" – Code of Conduct for the Energy Price Setting Plan;

Energy Price Setting Process is as set out in Schedule "B";

Energy Product means an agreement to supply power during a Base Period or Peak Period at a specified price;

Energy Return Margin or **ERM** is as set out in Section 2(b) of the Energy Price Setting Plan;

EPSP Code of Conduct means the rules and practices to which DERS and its affiliates will adhere while administering the EPSP as set out in Schedule "G" to the EPSP;

EU Act means the Electric Utilities Act, S.A. 2003, c.E-5.1 as amended;

Exchanges means i) Natural Gas Exchange Inc., and (ii) any other online internet trading system that may be established for trading electrical energy in Alberta;

Expiry Date of this EPSP is December 31, 2022;

External EPSP Development and Regulatory Costs or **EDR** has the meaning ascribed to it in Schedule "F" to the EPSP;

Final Settlement means the final calculation of settlement for a settlement month as described in AUC Rule 021: Settlement System Code Rules;

Forecast Load or **FL** means the forecast RRO usage in MW by hour determined in accordance with Schedule "C";

FPH or **Flat Product Hours** means the number of 7x24 hours in a month**;**

FPP or **Flat Product Price** or **Flat Block Procurement Price** means the weighted average price in $/MWh of the 7x24 Flat Products acquired for a Month;

FPV or **Flat Product Volume** means the Hedge Volume of the 7x24 Flat Products acquired for a Month;

FTL or the Forecast Total Load is the sum of the Forecast Load for a Month for each Rate Class including the distribution Line Loss Factor and the forecast Unaccounted for Energy for each Rate Class as determined in accordance with Schedule "C";

Full-Load Price means the price of a product that covers a percentage of load and settles as a financial swap against the Alberta hourly pool price with respect to consumer volume for each applicable hour;

Gains and Losses Without Commodity Risk Compensation, Energy Return Margin and Adders means Revenue Without Commodity Risk Compensation and Energy Return Margin minus Total Energy Portfolio Costs plus Spot Trades;

HE means "hour ending" and reflects the convention of measuring time by referencing the end of an hour during a day. For example, HE01 is the first hour of a day starting at midnight and ending at 00:59:59;

Hedge Volume means 7x24 Base Volume or 7x16 Peak Volume;

Independent System Operator or **ISO** means the corporation established by section 7 of the EUA;

Letter of Credit or **LOC** is a guarantee of payment issued by a bank on behalf of a client that is used as "payment of last resort" should the client fail to fulfill a contractual commitment with a third party;

Line Loss Factor or **LLF_{RC}** means the distribution line losses by Rate Class which will be determined by calculating the monthly line loss volumes as a percent of monthly metered volumes using the most recent six months of Final Settlement data for the Rate Class and taking the average of the monthly percentages;

Load Profile has the meaning ascribed to that term in AUC Rule 021: Settlement System Code Rules;

Market Surveillance Administrator or **MSA** means the entity established under section 42 of the Electric Utilities Act S.A. 2003 c. E-5.1;

Metered Forecast Load or **MFL** means the Forecast Load excluding distribution line losses and UFE;

Month means the calendar month with respect to which RRO Energy Charges are being established under this EPSP;

Monthly Settlement means the settlement data received for a settlement month approximately 3 weeks after the last day of the settlement month as described in AUC Rule 21: Settlement System Code Rules;

NGX means the online trading systems for electrical energy in Alberta operated by the Natural Gas Exchange, NGX Canada Inc. or any successor thereof;

NGX Collateral Costs or **NGXCC** means the costs incurred for posting financial security with the NGX in $/MWh determined in accordance with Section C.6 of Schedule "F" to the EPSP;

NGX Trading Charges and Transaction Fees or **NGXTC** means the $/MWh amount set by the NGX from time to time for load acquired or transacted on the NGX, determined in accordance with Section C.5 of Schedule "F";

OFFPFL means the Off Peak Forecast Load for the month;

$OFFPFL_{RC}$ means the Off Peak Forecast Load for a Rate Class for a Month;

OFFPFTL is the Off Peak Forecast Total Load for the Month and is calculated as $OFFPFTL = \Sigma\ OFFPFL_{RC} \times (1 + DLL_{RC})$ for all Rate Classes;

OFFPP means the Off Peak Price for the Month;

ONPFL is the On Peak Forecast Load for the Month;

$ONPFL_{RC}$ means the On Peak Forecast Load for a Rate Class for a Month and is equal to the total of the Forecast Load for the on peak hours for the Rate Class for the Month;

ONPFTL is the On Peak Forecast Total Load for the Month and is determined in accordance with section B.10 of Schedule "F";

OTC means over-the-counter;

Parental Corporate Guarantee or **PCG** is a guarantee of payment from a parent company for a subsidiary when the subsidiary enters into a contract with a counterparty;

Peak Block Procurement Price is the weighted average price paid by DERS for all the peak products procured for the Month;

Peak Period means the period from hours HE08 to HE23 Monday through Sunday inclusive;

Procurement Conduct Agreement means Appendix "G.1" to the EPSP;

Procurement Volume means the amount of Base Product and Peak Product that DERS requires in a Month;

Product means a Base Product or a Peak Product;

Protocol means the method for procuring product;

Quarter means a calendar quarter;

RAM means the Retail Adjustment to Market charges forecast for the Month;

Rate Class means the classes of customers eligible for RRO service under the RRO Regulation as designated by DERS and currently classified as follows: E1-Residential Service, E2-Small General Service, E3-Large General Service, E4-Oilfield Service, E5-Farm Service, E6-Lighting Service, and E7-Irrigation Pumping Service;

Revenue Without Commodity Risk Compensation and Energy Return Margin means the RRO revenue collected by the Company based on the weighted average BEC_{RC} grossed up for forecast Distribution Line Losses and Unaccounted for Energy;

RRO means the Regulated Rate Option;

RRO Customer means a "regulated rate customer" as defined in the RRO Regulation who accepts, uses or receives service from DERS at a Site located in the distribution service area of ATCO Electric;

RRO Regulation means the Regulated Rate Option Regulation, AR 262/2005, as amended, being the regulation that governs RRO service in the Province of Alberta;

RRO Site means a Site with respect to which an RRO Customer is the customer of record (as defined in DERS' RRO Tariff) for the Site;

RRO Tariff means the Tariff approved from time to time by the Commission pursuant to the EU Act and RRO Regulation respecting the provision of RRO Service by the Company in the distribution service areas in which the Company provides RRO service;

RRT Price Schedule means the Company's Price Schedule applicable to Regulated Rate Customers as approved from time to time by the Commission as part of the Company's RRO Tariff;

Seasonal Multiplier means the estimated regression coefficient (see Appendix F.1) used to quantify the relationship between DERS' and EEA's Full-Load Prices;

Site means a site as defined in AUC Rule 021: Settlement System Code Rules;

Spot Trades means the costs and revenues of clearing short and long positions at Alberta pool prices;

TEPC or **Total Energy Portfolio Cost** has the meaning ascribed to it in Schedule F;

Total Target Volume means, as the context requires, the 7x24 Base Volume or 7x16 Peak Volumes required for a Month;

Total Target Volume Blocks means, as the context requires, the 7x24 Base Volume Blocks or the 7x16 Peak Volume Blocks required for a Month;

UC is the Uplift Charge calculated in accordance with Section C.8 of Schedule "F";

Unaccounted for Energy or **UFE** means an amount of energy that is charged to DERS and represents energy that cannot be specifically allocated to a retailer or customer in accordance with Rule 021: Settlement System Code Rules, and is expressed as a percentage of customer usage;

Wholesale Class Information or **WCI** is the historical total consumption information that is provided by ATCO Electric for all sites by loss group and profile class for each settlement run;

and

Wholesale Settlement Detail or **WSD** is the historical consumption information that is provided by ATCO Electric at a site level.

Schedule "B"
to DERS' EPSP

ENERGY PRICE SETTING PROCESS

Capitalized terms used in this Schedule that are not otherwise defined herein have the meanings ascribed to them in Schedule "A" to the EPSP.

A. ENERGY ACQUISITION PROCESS

The Energy Price Setting Process begins with the Energy Acquisition Process under which the Company will procure energy supply for the Energy Portfolio.

The Company will procure over the Allowable Price Implementation Period energy supply for the Energy Portfolio in accordance with the methods and procedures for acquiring Energy Product set out below and in Schedule "D" and Confidential Schedule "E".

The Energy Portfolio will consist of Energy Products.

(a) DERS will procure as necessary the required Energy Portfolio in accordance with Confidential Schedule "E".

(b) The total volumes for the 7x24 Base Volume and 7x16 Peak Volume as determined in Schedule "D" to this EPSP will constitute the Hedge Volumes for the Month.

B. ENERGY PRICE SETTING PROCESS TIMELINES

The Energy Price Setting Process will begin no earlier than the first Business Day of the Allowable Price Implementation Period for each Month.

(a) The Energy Price Setting Process will end on the last Business Day prior to the end of the Allowable Price Implementation Period for each Month.

C. RRO ENERGY CHARGE

(a) Based on the procurement of the Energy Acquisition Process for the Month, five Business Days prior to the first day of the Month:

  (i) DERS will calculate the Base Energy Charge for each Rate Class for the Month using the method described in Schedule "F".

  (ii) DERS will calculate the RRO Energy Charge by Rate Class for the Month using the method described in Schedule "F".

Schedule "C"
to DERS' EPSP

FORECAST LOAD METHODOLOGY

Capitalized terms used in this Schedule that are not otherwise defined herein have the meanings ascribed to them in Schedule "A" to the EPSP.

A. RRO FORECAST LOAD METHODOLOGY

DERS will continue to utilize the forecasting system deployed across Direct Energy in order to complete its monthly and quarterly forecast. Forecasts will be developed at the rate class level.

1) **Forecast Total Load ("FTL")** for each Month will be determined as follows:

$$\mathbf{FTL = \sum FL_{RC} \times (1+DLL_{RC})}$$

where:

"FL_{RC}" is the Forecast Load for the Month for each rate class

"DLL_{RC}" is the Distribution Line Loss factor and the forecast Unaccounted for Energy for the Rate Class as determined in Section A.4 of this Schedule "C".

2) $\mathbf{FL_{RC} = (\sum (DSC_{RC} \times P_{RC} \times UF_{RC})) \times SF_{RC}}$

where:

"DSC_{RC}" is the current active site count by rate class

"P_{RC}" is the hourly profile by rate class for each week based on historical WCI data

"UF_{RC}" is the average weekly usage by rate class derived from the previous 3 years Final WSD settlement data

"SF_{RC}" is the site count factor applied to adjust the FTL for a net growth and attrition factor

3) **SF_{RC}** = average monthly net growth and attrition factor based on previous 2 year actual site count net growth/attrition calculated at the rate class level.

4) The Distribution Line Loss Factor and the forecast Unaccounted for Energy for the Rate

Class will be determined as follows:

$$\mathbf{DLL_{RC} = UFE_{RC} + LLF_{RC}}$$

where:

"UFE_{RC}" is the forecast Unaccounted for Energy for the Rate Class.

"LLF_{RC}" means the Line Loss Factor for the Rate Class.

a) The forecast Unaccounted for Energy (UFE_{RC}**)** for the Rate Class will be determined by calculating the average monthly Unaccounted for Energy over the most recent six calendar months for which Final Settlement is available for the Rate Class, as charged to the Company by the AESO.

b) The Line Loss Factor or LLF_{RC} means the distribution line losses by Rate Class which will be determined by calculating the monthly line loss volumes as a percent of monthly metered volumes using the most recent six months of Final Settlement data for the Rate Class and taking the average of the monthly percentages.

B. FORECAST LOAD UPDATES

1. The Forecast Load for each Month will initially be updated prior to the first day of the Allowable Price Implementation Period. It will be updated monthly, 90, 60 and 30 days prior to the Month using the latest available settlement data (excluding initial-daily settlement data) to update the UF_{RC}, SF_{RC}, and UFE_{RC} and utilizing the current active site count. The updated Forecast Load will be used to recalculate the Total Target Volumes and Total Target Volume Blocks for the Month in accordance with the methodology set out in Schedule "D" to this EPSP.

C. ADJUSTMENTS TO INPUT DATA

1. Notwithstanding anything in this schedule to the contrary, the "Actual" load, site count and profile data used for purposes of the calculations described in this Schedule will be adjusted as necessary to reflect changes in the eligibility of sites for RRO service resulting from modifications to the RRO eligibility criteria set out in section 1(d) of the RRO Regulation. The timing of the adjustments to the data made by the Company will reflect the timing of the implementation of the modifications to the RRO eligibility criteria in the RRO Regulation as announced by the Alberta Department of Energy. In the event that the Alberta Department of Energy announces its intention to implement such a modification to the RRO eligibility criteria, the Company will advise the Commission of its plan to reflect those changes in its RRO Forecast Load methodology prior to implementing them.

D. METHODOLOGY CHANGES

1. Any Forecast Load methodology improvements identified during the term of the EPSP will be filed for acknowledgement with the Commission prior to implementation. In the acknowledgement filing, DERS will include:

   i. An explanation of the change to the methodology or adjustment to the inputs to the forecast;
   ii. Supporting analysis for the change to the methodology or adjustment to the inputs to the forecast; and
   iii. A schedule that shows the history of all the changes to the methodology and changes to the inputs to the forecast.

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Schedule "D"
to DERS' EPSP

ENERGY PORTFOLIO HEDGE VOLUME DETERMINATION METHODOLOGY

Capitalized terms used in this Schedule that are not otherwise defined herein have the respective meanings ascribed to them in Schedule "A" to the EPSP.

A. HEDGE VOLUME DETERMINATION

1. The Average Hourly Total Target Volume respecting the 7x24 Base Volumes and 7x16 Peak Volumes required for a Month will be based on the Forecast Total Load prepared in accordance with Schedule "C", as follows:

    (a) The Average Hourly Total Target Volume respecting the 7x24 Base Volume required for the Month will be equal to the Off Peak Forecast Total Load (OFFPFTL) for the month divided by the number of days in the month divided by 8, rounded to the nearest 5 MW.

    (b) The Average Hourly Total Target Volume respecting the 7x16 Peak Volumes required for the Month will be equal to the On Peak Forecast Total Load (ONPFTL) for the month divided by the number of days in the month divided by 16, minus the 7x24 Base Volumes calculated in (a) above, rounded to the nearest 5 MW.

2. The Total Target Volume Blocks respecting the 7x24 Base Volume Blocks and 7x16 Peak Volume Blocks required for the Month will be determined as follows:

    (a) The 7x24 Base Volume Blocks will be equal to the 7x24 Base Volume determined in 1(a) divided by 5 MW.

    (b) The 7x16 Peak Volume Blocks will be equal to the 7x16 Peak Volume determined in 1(b) above divided by 5 MW.

**Confidential Schedule "E"
to DERS' EPSP**

PROTOCOL FOR PROCUREMENT

REDACTED

REDACTED

Direct Energy Regulated Services
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REDACTED

REDACTED

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REDACTED

REDACTED

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**Confidential Appendix "E.1"
to DERS' 2020-2022 EPSP
<u>REDACTED</u>**

Schedule "F"
to DERS' EPSP

ENERGY CHARGE APPLICABLE FOR EACH MONTH DURING THE PLAN TERM

Capitalized terms used in this Schedule that are not otherwise defined herein have the meanings ascribed to them in Schedule "A" to the EPSP.

A. RRO ENERGY CHARGE

The Energy Charge ("EC_{RC}") applicable to each RRO Rate Class for each Month will be determined as follows:

(1) $EC_{RC} = (BEC_{RC} + AESOTC) \times (1+DLL_{RC}) + ERM + RAM + UC + NGXTC + NGXCC + AESOCC + CCC + EDR$

where:

"BEC_{RC}" is the Base Energy Charge in $/MWh of the Energy Portfolio for the Rate Class for the Month determined in accordance with Section B of this Schedule "F" to the EPSP.

"AESOTC" are the AESO Trading Charges in $/MWh determined in accordance with Section C.1 of this Schedule "F" to the EPSP.

"DLL_{RC}" is the Distribution Line Loss factor and the forecast Unaccounted for Energy for the Rate Class as determined in accordance with Section A.4 of Schedule "C" to the EPSP.

"ERM" is the Energy Return Margin as set out in Section 2(b) of the document entitled "2020-2022 Energy Price Setting Plan (Index)" and will be $2.83/MWh grossed up by applying the Effective Tax Rate.

"RAM" is the Retail Adjustment to Market charge forecast for the Month in $/MWh determined in accordance with Section C.7 of this Schedule "F" to the EPSP.

"UC" are the Uplift Charges in $/MWh determined in accordance with Section C.8 of this Schedule "F" to the EPSP.

"NGXTC" are the NGX Trading Charges and Transaction Fees in $/MWh determined in accordance with Section C.5 of this Schedule "F" to the EPSP.

"NGXCC" are the NGX Collateral Costs in $/MWh determined in accordance with Section C.6 of this Schedule "F" to the EPSP.

"AESOCC" are the AESO Collateral Costs in \$/MWh determined in accordance with Section C.2 of this Schedule "F" to the EPSP.

"CCC" are the Counterparties Collateral Costs in \$/MWh determined in accordance with Section C.4 of this Schedule "F" to the EPSP.

"EDR" are the External EPSP Development and Regulatory costs in \$/MWh determined in accordance with Section C.3 of this Schedule "F" to the EPSP.

B. RATE CLASS ENERGY PRICE DETERMINATION

The Base Energy Charge ("BEC_{RC}") for the Month for each Rate Class will be determined as follows:

(2) $$\mathbf{BEC_{RC} = P_{FL\_ON} \times FTL\%_{RC\_ON} + P_{FL\_OFF} \times FTL\ \%_{RC\_OFF}}$$

$\mathbf{FTL\ \%_{RC\_ON}}$ is the total peak load forecast as a percentage of **FTL** by rate class.
$\mathbf{FTL\ \%_{RC\_OFF}}$ is the total off-peak load forecast as a percentage of **FTL** by rate class.

$\mathbf{P_{FL}}$ is the Full-Load Price for DERS, based on the EEA Monthly RRO Filing.

(3) $$\mathbf{P_{FL} = M \times (PFL_{EEA} - PF_{EEA}) + P_{B\_F}}$$

M is the Seasonal Multiplier estimated according to the methodology outlined in Appendix F.1.

$\mathbf{PFL_{EEA}}$ is the EEA Full-Load Price from the EEA Monthly RRO Filing.

$\mathbf{PF_{EEA}}$ is the EEA Flat Price from the EEA Monthly RRO Filing.

$\mathbf{P_{B\_F}}$ is DERS' Flat Block Procurement Price.

$\mathbf{P_{FL\_OFF}}$ is the estimated Full-Load Price for the Off-Peak period.

(4) $$\mathbf{P_{FL\_OFF} = P_{B\_OFF} \times FLP_{RATIO}}$$

$\mathbf{P_{B\_OFF}}$ is the Derived Off-Peak Block Procurement Price.

(5) $\mathbf{P_{B\_OFF} = (H_F \times P_{B\_F} - H_{ON} \times P_{B\_ON}) / (H_F - H_{ON})}$

$\mathbf{H_F}$ **=** the total hours in the Month

$\mathbf{H_{ON}}$ **=** the total hours in the Peak Period for the Month.

$\mathbf{P_{B\_F}}$ **=** DERS' Flat Block Procurement Price

$\mathbf{P_{B\_ON}}$ = DERS' Peak Block Procurement Price

$\mathbf{P_{B\_OFF}}$ **=** DERS' Derived Off-Peak Block Procurement Price

$\mathbf{P_{FL\_ON}}$ is the estimated Full-Load Price for the Peak Period.

(6) $\mathbf{P_{FL\_ON} = P_{B\_ON} \times FLP_{RATIO}}$

$\mathbf{FLP_{Ratio}}$ is the Full-Load Price divided by the total-load-weighted block procurement price.

(7) $\mathbf{FLP_{Ratio} = P_{FL} / P_{B\_W}}$

(8) $\mathbf{P_{B\_W} = FTL\ \%_{ON} \times P_{B\_ON} + FTL\ \%_{OFF} \times P_{B\_OFF}}$

$\mathbf{FTL\ \%_{ON}}$ is the total peak load forecast as a percentage of **FTL** across all rate classes.

$\mathbf{FTL\ \%_{OFF}}$ is the total off-peak load forecast as a percentage of **FTL** across all rate classes.

Backstop CRC Calculation

If there is not an EEA Full-Load Price in the EEA Monthly RRO Filing provided for the Month, the Backstop CRC will be applied to the procurement-volume-weighted block procurement price (Peak and Flat Block Procurement Prices weighted by Peak and Flat Block procurement volumes) to determine the Full-Load Price instead of Formula (3). This is detailed in Formula (9) below.

(9) $\mathbf{P_{FL} = P_{B\_PW} \times (1 + CRC_{12MA\%})}$

$\mathbf{P_{B\_PW}}$ is the procurement-volume-weighted block procurement price.

$\mathbf{CRC_{12MA\%}}$ is the percentage of total CRC to Revenue Without Commodity Risk Compensation and Energy Return Margin over the past twelve months. For any month in that twelve-month period where there was not an EEA Full-Load Price in the EEA Monthly RRO Filing, the CRC amount is replaced with that month's Gains and Losses Without Commodity Risk Compensation, Energy Return Margin and Adders.

(10) $$\mathbf{CRC_{12MA\%}} = \frac{\sum_{\mathbf{m=1}}^{\mathbf{12}} \mathbf{if(n_m = 1, CRC_m \times U_m\,, L_m)}}{\sum_{\mathbf{m=1}}^{\mathbf{12}} \mathbf{BECWOCRC_m \times U_m}}$$

m is the previous-month index from 1 to 12
n equals 1 in months where there is a Full-Load Price in the EEA Monthly RRO Filing.
$\mathbf{CRC_m}$ is the monthly CRC on a $/MWh basis.
$\mathbf{U_m}$ is monthly customer usage.
$\mathbf{BECWOCRC_m}$ is the BEC without CRC in month m.

$\mathbf{L_m}$ is the monthly Gains and Losses Without Commodity Risk Compensation, Energy Return Margin and Adders for month m for which Monthly Settlement data is available. Calculation of L_m will use the most recent settlement data, excluding daily settlement.

C. COST ADDER CALCULATIONS

1) The AESO Trading Charges ("**AESOTC**") for the Month will be the current AESO Trading Charges set by the ISO from time to time expressed in $/MWh.

2) The AESO Collateral Costs ("**AESOCC**") for the Month will be the AESO credit limit multiplied by the sum of the most recent AUC approved annual rate for Parental Corporate Guarantees ("PCG") costs divided by 12 plus the Letter of Credit ("**LOC**") cost divided by 12. These costs shall be divided by the MFL for the Month to derive the monthly cost adder.

3) The External EPSP Development and Regulatory Costs ("**EDR**") for the Month will be determined as follows:

   a) With respect to costs incurred by the Company prior to the first Month of the EPSP, the EPSP Implementation Costs will include:

      i.) all of the Company's external costs (including legal and consulting fees, and disbursements) associated with:

         a) The development and preparation of the EPSP.

         b) The preparation and filing with the AUC of the Application for approval of the EPSP and all aspects of the AUC's regulatory approval process for the EPSP.

      ii.) intervener hearing costs approved for recovery by the AUC in respect of the AUC's regulatory approval process referred to in (i) above.

      One-twelfth of the total of the costs identified in this subsection (a) will be included in the calculation of the RRO Energy Charge for each of the first 12 Months of the EPSP.

   b) With respect to costs incurred by the Company after the beginning of the first Month of the EPSP, EDR costs will include:

      i.) all of the Company's external costs (including legal and consulting fees, and disbursements) associated with:

         a) The development and preparation of any amendments to the EPSP.

         b) The preparation and filing with the AUC of any Applications for approval of such amendments and all aspects of the AUC's regulatory approval process for the amendments.

      ii.) intervener hearing costs approved for recovery by the AUC in respect of the AUC's regulatory approval process referred to in (i) above.

      One-twelfth of the total of the costs identified in this subsection (b) will be included in the calculation of the RRO Energy Charge a Month following the implementation of the amendment.

   c) The implementation costs associated with ongoing implementation of the EPSP will be applied to the Month in which the costs occur;

   d) Any EPSP EDR costs that occurred under previous EPSPs that were not fully recovered while they were in force will constitute EDR costs under this EPSP and

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will be recovered by DERS under this EPSP over a time period determined by DERS, acting reasonably;

e) The total costs for each Month calculated in a), b), c) and d) above will be divided by the MFL for the Month and expressed as a $/MWh amount.

4) The Counterparties Collateral Costs ("**CCC**") adder in $/MWh will be determined on a monthly basis as the sum of the estimated dollar amount of Parental Corporate Guarantees (PCG) issued on behalf of RRO Customers multiplied by the most recent AUC approved annual rate for PCG divided by 12. These costs shall be divided by the MFL for the Month to derive the monthly cost adder.

5) The NGX Trading Charges and Transaction Fees ("**NGXTC**") will be all broker and NGX fees divided by the MFL to arrive at the applicable $/MWh amount.

6) NGX Collateral Costs ("**NGXCC**") in $/MWh to be included in the RRO Energy Charge will be determined on a monthly basis as the estimated dollar amount of Parental Corporate Guarantees (PCG) issued on behalf of Regulated Rate Customers for NGX multiplied by the most recent AUC approved annual rate for PCG divided by 12 plus the dollar amount of Letters of Credit (LOC) issued multiplied by the actual LOC costs divided by 12. These costs shall be divided by the MFL for the Month to derive the monthly cost adder.

7) Retail Adjustment to Market ("**RAM**") charges will be the average of the last 12 months of RAM charges incurred divided by the MFL for the Month and expressed as a $/MWh amount.

8) The Uplift Charges ("**UC**") will be the average of the last 6 months of AESO uplift charges incurred divided by the MFL for the Month and expressed as a $/MWh amount. In the event that the AESO ceases charging the Company uplift charges, the UC will be set to zero once the six month average calculates to zero.

D. COMMODITY RISK COMPENSATION

The Commodity Risk Compensation ("**CRC**") is embedded in the Full-Load Price but can be derived as follows:

$$CRC = P_{FL} - P_{B\_PW}$$

Appendix "F.1"
Seasonal Multiplier Estimation Methodology

The estimate of the Seasonal Multipliers was obtained through a linear regression analysis that quantified the relationship between DERS' and EEA's monthly load-following costs (LFC). The sample period of the data begins January 1, 2008 and ends August 31, 2020. The regression equation estimated was:

$$LFC_m^{DERS} = M_0 \times LFC_m^{EEA} + D \times M_1 \times LFC_m^{EEA}$$

Where,

m indicates the Month

$D = 0$ when the Month is Oct-Mar, and $D = 1$ when the month is Apr-Sep.

The Seasonal Multiplier $M{=}M_0$ during Oct-Mar, and $M{=}M_0 + M_1$ during Apr-Sep.

$$LFC_m^{DERS} = \frac{\sum_{h=1}^{H} V_h^{DERS} \times P_h}{\sum_{h=1}^{H} V_h^{DERS}} - \frac{\sum_{h=1}^{H} P_h}{H}$$

$$LFC_m^{EEA} = \frac{\sum_{h=1}^{H} V_h^{EEA} \times P_h}{\sum_{h=1}^{H} V_h^{EEA}} - \frac{\sum_{h=1}^{H} P_h}{H}$$

Where,

V_h^{DERS} is the final settlement volume from the AESO Metered Volumes report for DERS for the hour h.

V_h^{EEA} is the final settlement volume from the AESO Metered Volumes report for EEA for the hour h.

P_h is the posted Alberta pool price in hour h.

H is the last hour of month m.

The regression coefficient estimates were M_0 = 0.941, and for M_1 = -0.106. Hence, the Seasonal Multiplier used in Formula (3) of Section F will be 0.941 during October through March and 0.835 April through September.

In the compliance filing DERS shall make one year after the implementation of this EPSP, the regression coefficients will be re-estimated to account for additional available data. If there is a material change to the regression coefficients, then DERS will apply to amend the 2020-2022 EPSP concurrently with the compliance filing.

Schedule "G"
to DERS' EPSP

CODE OF CONDUCT FOR THE ENERGY PRICE SETTING PLAN

1. All personnel of Direct Energy Marketing Limited ("DEML") who are privy to the Confidential Schedule "E" relied on by the Energy Price Setting Plan, developed for the purposes of setting energy prices are required to sign a Procurement Conduct Agreement requiring them to keep all Confidential Schedule "E" information strictly confidential and to not disclose to any other person or use, except for the purposes of the Energy Price Setting Plan. A copy of the Procurement Conduct Agreement is attached as Appendix "G.1" to the EPSP.

2. Any consultants ("Consultants") retained by DEML in respect of the Energy Price Setting Plan will be required to sign confidentiality agreements requiring them to keep Confidential Schedule "E" information strictly confidential and to not disclose to any other person or use, except for the purposes of the Energy Price Setting Plan.

3. If DEML or any Consultants retained by DEML in respect of the EPSP become aware of an unauthorized disclosure or unauthorized use, or a possible unauthorized disclosure or unauthorized use, of Confidential Schedule "E" information ("Possible Unauthorized Use or Disclosure") that party will immediately report that concern to the Company who will work with the Market Surveillance Administrator ("MSA") to resolve the concern.

4. If, after discussing the concern with the MSA, if the concern remains unresolved, DEML will apply to the Alberta Utilities Commission ("AUC" or "Commission") to have the issue addressed, and will request that the Commission and its process respect the confidential nature of the Confidential Schedule "E" information and other matters to be addressed to the extent permitted under the Commission's Rules of Practice.

Appendix "G.1"
to DERS' EPSP

PROCUREMENT CONDUCT AGREEMENT

TO: DIRECT ENERGY MARKETING LIMITED

WHEREAS:

(a) Direct Energy Marketing Limited ("DEML") has adopted the energy price setting method set out in its Energy Price Setting Plan ("EPSP") for the purposes of acquiring an energy supply and setting the energy price for RRO Customers. Implementation of the EPSP will involve product procurement to acquire an energy supply including the use of alternative mechanisms such as forward contracts.

(b) The EPSP, as amended and adjusted from time to time, relies on specific pricing parameters developed for the purposes of setting energy price. The disclosure of the "Confidential Schedule "E" could adversely affect the Company's ability to acquire energy supplies and/or the costs incurred by the Company to acquire those supplies.

(c) DEML has made efforts to identify, and to organize and manage the involvement of directors, officers, employees and agents that have been involved or may become involved with the matters addressed in this Procurement Conduct Agreement.

NOW THEREFORE, in consideration of being permitted to become involved with the matters addressed in this Procurement Conduct Agreement, the undersigned agrees, acknowledges and confirms as follows:

1. The undersigned has read and understands the attached confidentiality provisions of the Procurement Conduct Agreement and agrees to abide by these provisions and their spirit and intent. In particular, until the date the EPSP is no longer used or intended to be used for the purposes of energy price setting for RRO Energy Charges, subject to section 2 below, the undersigned agrees to keep the Confidential Schedule "E" strictly confidential and to not disclose to any other person, except for the purposes of the EPSP.

2. The provisions of this Procurement Conduct Agreement relating to Confidential Schedule "E" will not apply to any part that is now or subsequently becomes part of the public domain through no violation of the Procurement Conduct Agreement.

3. If the undersigned becomes aware of a breach, or of any information the undersigned believes may indicate a breach, by any other person who is a party to an agreement corresponding to this Procurement Conduct Agreement, the undersigned will immediately report that breach or possible breach to a member of the compliance team and to the Market Surveillance Administrator and conduct himself or herself in accordance with their direction.

4. The undersigned acknowledges that the mishandling or unauthorized use or disclosure by the undersigned of Confidential Schedule "E" could cause irreparable harm and significant injury to DEML and/or its subsidiaries.

5. The undersigned understands that a breach of this Procurement Conduct Agreement could result in disciplinary action, if intentional, including possible termination of his or her employment or possible civil or criminal proceedings against the undersigned.

AGREED TO this ____ day of__________, 20__.

____
Name and Title