Decision **27950-D01-2023**

Alberta Utilities Commission

Direct Energy Regulated Services

2023-2025 Energy Price Setting Plan Compliance Filing

February 28, 2023

Alberta Utilities Commission
Decision 27950-D01-2023
Direct Energy Regulated Services
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Proceeding 27950

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The Commission may, no later than 60 days from 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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Alberta Utilities Commission
Calgary, Alberta

Direct Energy Regulated Services
2023-2025 Energy Price Setting Plan
Compliance Filing

Decision 27950-D01-2023
Proceeding 27950

1 Decision summary

1. The Alberta Utilities Commission is satisfied that Direct Energy Regulated Services' (DERS) 2023-2025 energy price setting plan (EPSP) compliance filing is complete and complies with the applicable directions set out in Confidential Decision 27562-D01-2022.[1]

2. DERS can begin procurement under its Commission-approved 2023-2025 EPSP attached as Appendix 2 to this decision in March 2023. The result will be that July 2023 will be the first month energy charges will be set in accordance with the 2023-2025 EPSP.

3. July 2023 energy charges will use an energy return margin calculated using DERS' 2022 financials submitted via its Rule 005: *Annual Reporting Requirements of Financial and Operational Results* filing before May 1, 2023. The Commission notes that the initial energy return margin submitted as part of this compliance filing is therefore not needed, and grants DERS relief from that specific direction.

2 Background

4. Monthly regulated rate option (RRO) energy rates are determined pursuant to the *Electric Utilities Act*, in accordance with the *Regulated Rate Option Regulation* and with the EPSP approved by the Commission.

5. DERS' approved EPSP establishes the pricing of electricity for RRO customers in ATCO Electric Ltd.'s distribution service territory as appointed by it under Section 104 of the *Electric Utilities Act*.

6. On December 22, 2022, the Commission issued Confidential Decision 27562-D01-2022, in which it included its findings on an application from DERS for approval of its 2023-2025 EPSP. The Commission did not approve the EPSP as filed and directed DERS to make changes to the EPSP, to the accompanying illustrative energy charge workbook and to the calculation of the initial return margin, and to submit a compliance filing to reflect the Commission's findings and directions.

7. On January 16, 2023, DERS submitted its 2023-2025 EPSP compliance filing to the Commission.

8. The Commission issued a notice of application on January 19, 2023. The notice stated that the Commission considered the compliance filing to be routine in nature and uncontentious.

[1] Confidential Decision 27562-D01-2022: Direct Energy Regulated Services, 2023-2025 Energy Price Setting Plan, Proceeding 27562, December 22, 2022.

Consequently, the Commission stated a decision on the application would be made with no further notice, unless an intervener challenged the Commission's designation of routine by filing a statement of intent to participate (SIP) by no later than January 27, 2023. No SIPs were filed. The Commission considers that the close of record for this proceeding was January 27, 2023.

3 Details and Commission findings

9. The compliance filing included a public, redacted and confidential 2023-2025 EPSP, an illustrative energy charge workbook and an initial energy return margin calculation.

3.1 Changes directed to be made to the 2023-2025 EPSP

10. In Confidential Decision 27562-D01-2022 and Decision 27562-D01-2022, the Commission directed DERS to incorporate a number of changes to the 2023-2025 EPSP, filed in Proceeding 27562. The changes are as follows:

[redacted] [redacted][2]

[redacted] [redacted]

[redacted][3]

[redacted] [redacted][4]

[redacted] [redacted][5]

- Amend the description of the calculation of the energy return margin by setting out that the net commodity risk compensation has to be removed from the revenues used in that calculation.[6]

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[2] As directed in paragraph 15 of Confidential Decision 27562-D01-2022.
[3] Paragraph 24 of Confidential Decision 27562-D01-2022.
[4] As directed in paragraph 31 of Confidential Decision 27562-D01-2022.
[5] As directed in paragraph 37 of Confidential Decision 27562-D01-2022.
[6] As directed in paragraph 46 of Decision 27562-D01-2022.

Commission findings

11. The Commission reviewed the public, redacted EPSP and the confidential EPSP that DERS filed as part of the compliance filing. It finds that the changes directed in Decision 27562-D01-2022, as listed above, have been incorporated in those documents, with one exception. The description of the energy return margin calculation in Section E of Schedule F of the public, redacted EPSP and the confidential EPSP is as follows:

> On an annual basis, in July, the after-tax Energy Return Margin will be updated as a mark-up of Energy Revenue, D&T Revenue and Non-Energy Revenue, excluding Municipal Franchise Fees and Return Revenue, expressed in $/MWh and will be calculated as follows:[7]

12. The Commission notes that the description does not include wording to indicate that the net commodity risk compensation (Net CRC) has to be excluded from the revenues used in the calculation. The Commission amended the wording in the approved 2023-2025 EPSP attached as Appendix 2 to this decision to incorporate the required change. The amended wording is as follows:

> On an annual basis, in July, the after-tax Energy Return Margin will be updated as a mark-up of Energy Revenue, D&T Revenue and Non-Energy Revenue, excluding Municipal Franchise Fees, Return Revenue and Net CRC, expressed in $/MWh and will be calculated as follows:

13. Based on its review of the public, redacted EPSP and the confidential EPSP that DERS filed as part of the compliance filing, and the Commission's amendment to the EPSP documents as described above, the Commission approves the 2023-2025 EPSP, and finds that DERS has complied with the directions listed in paragraph 10.

3.2 Changes directed to be made to the illustrative energy charge workbook

14. In paragraph 46 of Decision 27562-D01-2022 the Commission directed DERS to amend the illustrative energy charge workbook filed in Proceeding 27562 to incorporate the amended wording and formula for the calculation of the energy return margin.

Commission findings

15. The Commission reviewed the illustrative energy charge workbook that DERS filed as Exhibit 27950-X0004 and finds that it incorporated the updated formula for the calculation of the energy return margin. Therefore, the Commission approves the illustrative energy charge workbook as filed in Exhibit 27950-X0004 and finds that DERS has complied with the direction from paragraph 46 of Decision 27562-D01-2022.

3.3 Changes directed to be made to the initial energy return margin

16. In paragraph 46 of Decision 27562-D01-2022 the Commission directed DERS to recalculate and submit the initial return margin to be used in the 2023-2025 EPSP, by excluding the Net CRC for 2021 and include details of the recalculation. DERS submitted the information in Exhibit 27950-X0005.

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7 Exhibit 27950-X0003, page 29. Confidential Exhibit 27950-X0010-C, page 29.

Commission findings

17. The initial energy return margin that incorporates DERS' 2021 financial results, as submitted in its Rule 005 report in April 2022, would have been included as part of the RRO energy charges calculated under the 2023-2025 EPSP up to and including June 2023. The energy return margin for July 2023 to June 2024 will be calculated using DERS' 2022 financial results, which will be submitted in its upcoming Rule 005 report by May 1, 2023.

18. Given the timing, energy charges under the approved 2023-2025 EPSP will not use the initial energy return margin submitted as part of this compliance filing. Procurement will begin in March 2023, the month following the month this decision was issued in. As a result, the first month that energy charges under the 2023-2025 EPSP will be used is July 2023. As mentioned above, the July 2023 energy charge calculation will use DERS' 2022 financial results submitted this year. Consequently, the Commission finds that it does not have to review or approve the initial return margin, and grants DERS relief from complying with that specific direction in paragraph 46 of Decision 27562-D01-2022.

3.4 Compliance filing

19. In paragraph 64 of Decision 27562-D01-2022 the Commission directed DERS to submit a compliance filing on or before January 18, 2023, that incorporated all of the Commission's findings and directions in that decision. The Commission indicated that the compliance filing should include an updated public and confidential 2023-2025 EPSP, and an updated illustrative energy charge workbook.

Commission findings

20. The compliance filing was submitted on January 16, 2023, and included an updated public and confidential 2023-2025 EPSP, and an updated illustrative energy charge workbook. Based on that information, its previous findings in this decision, the Commission's amendment to Section E of Schedule F of the 2023-2025 EPSP to incorporate the Net CRC, and the Commission's granting of relief from DERS having to comply with the direction regarding the initial return margin, the Commission finds that DERS has complied with the direction in paragraph 64 of Decision 27562-D01-2022.

4 Commission-approved 2023-2025 EPSP

21. Based on its previous findings regarding DERS' compliance with the applicable directions from Decision 27562-D01-2022 relating to the 2023-2025 EPSP, the Commission approves the 2023-2025 EPSP, attached as Appendix 2 to this decision. In addition to including the amendment the Commission made to Section E of Schedule F of the 2023-2025 EPSP filed by DERS, as previously described, the attached 2023-2025 EPSP includes some minor typographical and wording changes to the documents that were filed by DERS.[8]

[8] The number of pages in the header in the public EPSP and the confidential EPSP changed from 32 to 33. On page 10 of the public EPSP and the Confidential EPSP, the font size for the term "Tax Rate," and its definition, was changed from Times New Roman 11 to Times New Roman 12. On page 23 of the public EPSP, in the definition of the term "ERM," a comma was added after the word "document" in the first line. [redacted]

22. Procurement under the approved 2023-2025 EPSP will commence in March 2023, the first month after the month this decision is issued. Following the 120-day price setting period set out in Section 11(2) of the *Regulated Rate Option Regulation*, July 2023 will be the first month for which energy charges will be calculated under the 2023-2025 EPSP.

23. The expiry date of the approved 2023-2025 EPSP is December 31, 2025, which means that the energy charges for December 2025 will be the last energy charges calculated under the approved 2023-2025 EPSP, unless DERS requests and receives Commission approval to extend the term.

5 Monthly filings under the 2023-2025 EPSP

24. Section 12 of the *Regulated Rate Option Regulation* requires that "An owner must submit to its regulatory authority, not less than 5 business days prior to the commencement of each calendar month, the regulated rate for that calendar month and the calculations of the regulated rate." DERS submits the following documents as part of its monthly electric energy charge filings under its current EPSP: (i) a cover letter; (ii) a rate calculation Excel workbook; (iii) a director attestation letter; (iv) a trader attestation letter; (v) Rate Rider P schedules; (vi) Rate Rider P (rural electrification association) schedules; (vii) a forecast variance analysis report; and (viii) a confidential procurement review document. The Commission expects DERS to file the same documents as part of its monthly filings under the 2023-2025 EPSP.

25. The Commission also reminds DERS about the information it is required to file as part of its future Rule 005 reports, as directed in paragraph 50 of Decision 27562-D01-2022, and the information it is required to file as part of the annual updating of the seasonal multipliers, as directed in paragraph 63 of Decision 27562-D01-2022.

6 Order

26. It is hereby ordered that:

(1) The 2023-2025 energy price setting plan of Direct Energy Regulated Services, attached as Appendix 2 to this decision, is approved.

Dated on February 28, 2023.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

Appendix 1 – Proceeding participants

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

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair Commission staff K. O'Neill D. Mitchell

Appendix 2 – Commission-approved 2023-2025 energy price setting plan

(return to text)

Appendix 2 -
2023-2025 EPSP - Re

(consists of 33 pages)

DIRECT ENERGY REGULATED SERVICES

2023-2025 ENERGY PRICE SETTING PLAN

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.

(b) Energy Return Margin

The Energy Return Margin will be set at an after tax return mark-up of DERS' total revenues, which revenues shall equal the sum of DERS' energy revenues, non-energy revenues and distribution and transmission revenues less municipal franchise fees, before-tax return revenues and net CRC. The after-tax margin thus calculated shall be grossed up for taxes by applying the Effective Tax Rate and will be collected on a $/MWh basis through the energy charge cost component of customer bills for the total RRO load. The Company will update the Energy Return Margin annually in accordance with Section E of Schedule F.

(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, 2025.

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 “2023-2025 Energy Price Setting Plan” 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, 2025;

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;

Tax Rate means the combined federal and provincial tax rates for the year reported in DERS' Rule 005 filing.

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.

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.

If the Total Target Volume Blocks have been acquired for a month, but are subsequently revised down due to an update of the Total Forecast Load for that Month, as per Schedule "C" part B, then the previously determined Total Target Volumes Blocks will be considered the final Total Target Volumes Blocks.

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

<u>PROTOCOL FOR PROCUREMENT</u>

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

**Confidential Appendix “E.1”
to DERS’ 2023-2025 EPSP**

REDACTED

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 this document, ERM will be grossed up by applying the Effective Tax Rate and is determined by dividing the after-tax Energy Return Margin as calculated in Section E below by one minus 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) $\mathbf{P_{B\_OFF} = (H_F \times P_{B\_F} - H_{ON} \times P_{B\_ON}) / (H_F - H_{ON})}$

H_F = the total hours in the Month

H_{ON} = the total hours in the Peak Period for the Month.

P_{B_F} = DERS' Flat Block Procurement Price

P_{B_ON} = DERS' Peak Block Procurement Price

P_{B_OFF} = DERS' Derived Off-Peak Block Procurement Price

P_{FL_ON} is the estimated Full-Load Price for the Peak Period.

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

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

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

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

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

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 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:

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

E. Energy Return Margin

On an annual basis, in July, the after-tax Energy Return Margin will be updated as a mark-up of Energy Revenue, D&T Revenue and Non-Energy Revenue, excluding Municipal Franchise Fees, Return Revenue and Net CRC, expressed in $/MWh and will be calculated as follows:

(9) $ERM_{\text{after-tax}}$ = (Energy Revenue + D&T Revenue + Non-Energy Revenue – MFF – Return Revenue – Net CRC) x Return Mark-Up/ Energy Sales

Energy Revenue is the Energy Revenue reported in DERS' Rule 005: *Annual Reporting Requirements of Financial and Operational Results* filing.

D&T Revenue is the D&T Revenue reported in DERS' Rule 005 filing.

Non-Energy Revenue is the Non-Energy Revenue reported in DERS' Rule 005 filing.

MFF is the Municipal Franchise Fees reported by DERS for the year and calculated based on ATCO Electric Ltd. Municipal Franchise Fees.

Return Revenue is the before-tax Return Revenue reported in DERS' Rule 005 filing.

Net CRC is the Commodity Risk Compensation (CRC) received plus the Commodity Gain/(Loss).

Energy Sales is the RRT Total Energy Sales in MWh reported in DERS Rule 005 filing.

Return Mark-up is the after-tax reasonable Return Mark-up calculated as 1.30% x (1 - Tax Rate) / (1 –Tax Rate – 1.30%), rounded to the 2nd percentage decimal place.

$ERM_{\text{after-tax}}$ is the after-tax Energy Return Margin.

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 June 30, 2022. 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 $M_0 = 0.909$, and for $M_1 = -0.0634$.

Hence, the Seasonal Multiplier used in Formula (3) of Section F will be as follows:

Term	**Seasonal Multiplier**
January 1, 2023-March 31, 2023	0.909
April 1, 2023-June 30, 2023	0.846
July 1, 2023, July 1, 2024 and July 1, 2025	New Seasonal Multipliers will be determined for each year based on the most recent settlement data.

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