NECOM
NATIONAL ENERGY CRISIS COMMITTEE

The South African Wholesale Electricity Market Specification

April 2024

Contents

Abbreviations

BRP	Balance responsible party
CCGT	Combined cycle gas turbine
CfD	Contract for Difference
CRM	Capacity Remuneration Mechanism
CPA	Central Purchasing Agency
DAM	Day Ahead Market
DMRE	Department of Mineral Resources and Energy
ERA	Electricity Regulation Act
ESI	Electricity Supply Industry
FiT	Feed-in-Tariffs
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit
IPP	Independent power producer
NERSA	National Energy Regulator of South Africa
NTCSA	National Transmission Company of South Africa
PPAs	Power Purchase Agreements
REIPPP	Renewable Independent Power Producer Programme
RES	Renewable Energy Sources
SAPP	Southern African Power Pool
SMP	System marginal price
TSMO	Transmission System and Market Operator

1. Introduction

This Market Specification document has been developed to support the understanding of the South African multi-market model as defined in the Electricity Regulation Act (ERA) Amendment Bill. It serves as a high-level description of the market model and describes the following underlying concepts:

a) The South African electricity supply industry

b) Market concept and the key market features

c) Regulatory structures

d) International markets

e) The key functions of the Central Purchasing Agency (CPA)

f) The use of Contracts for Difference (CfD)

g) The use of Capacity Remuneration Mechanisms (CRM)

This specification document, the associated market code represent works in progress, which will continue to evolve over time and with industry input. This proposal has been developed under the auspices of the nascent Market Operator within the National Transmission Company of South Africa (NTCSA), the party designated as responsible for developing a market code and rules.

The Market Operator would also like to acknowledge the support of the South African German Energy Program (SAGEN), funded by the German government and implemented by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), Bredesen Consulting and Nord Pool Consulting in developing this document.

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In the title for all emails with comments or questions on this document, please include "Market

Specification document comment".

2. Governing electricity policy and regulation

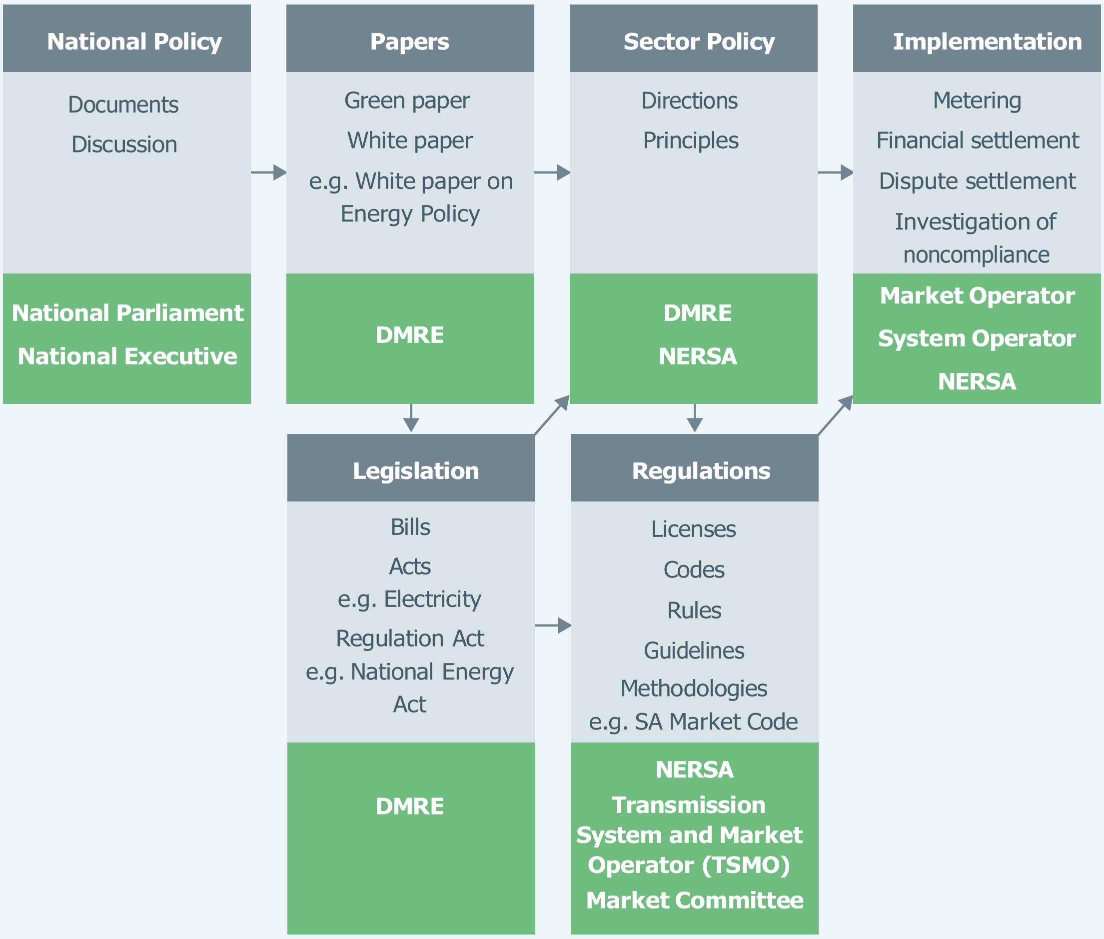

Figure 1. Regulatory and legislative environment for the South African electricity supply industry and market (adapted from the Electricity

Figure 1 illustrates the regulatory and legislative environment for the South African electricity supply industry. At the highest level of governance are national documents and discussions by the **National Parliament** or the **Executive**. These address priority multisectoral issues, for example, the National Development Plan 2030 and State of the Nation addresses, which in 2019 and 2022 respectively announced the intention to unbundle Eskom into separate generation, transmission and distribution entities and to move to a competitive electricity market. White or green papers and legislation provide high-level guidance within the sector and are therefore the jurisdiction of the

Department of Mineral Resources and Energy (DMRE). "White Paper on the Energy Policy of the Republic of South Africa", which was introduced in 1998 outlined several reforms and market liberalisation measures. The Electricity Regulation Act (ERA) of 2006 is currently being amended through the ERA Amendment Bill. This amendment bill addresses the ESI's market structure, the establishment of a Transmission System Operator and different stakeholder's regulatory responsibilities within the reformed sector. The subsequent level of regulatory framework consists of sector policy and regulations; these are documents with detailed specifications for how elements of ESI and market would operate. The new South African Market Code would fit within this level and would be maintained by the **Transmission System and Market Operator** (TSMO) as the secretariat. In addition, it is expected that a Market Committee will be formed by industry stakeholders and ultimately approved by NERSA. The Market Committee will play a supporting role in maintaining and updating the market rules. The details of the foundation, rules and operation of this committee shall be defined in the Market Code.

3. The South African electricity supply industry

The transition to a competitive market model will be based on a stepwise implementation of various market segments, as well as a phased introduction of participants to the South African power market. To understand the processes required within an electricity market, it is valuable to outline the relevant stakeholders and how they participate in the industry.

The operationalization of the NTCSA, seen as the cornerstone of the unbundling of Eskom, is well advanced, with a board appointed and licenses granted by the National Energy Regulator of South Africa (NERSA) for transmission, import, export and trading. Within a market environment, the duties of the NTCSA include being a transmitter, system operator, market operator and being responsible for certain mitigation and transition measures through a special purpose vehicle called the **Central Purchasing Agency (CPA)** (detailed in Chapter 4)**.**

The generation mix is currently dominated by Eskom Generation, which supplies approximately 90%, with the balance of the mix stemming from centrally procured capacity through the Renewable Energy Independent Power Producer Procurement (REIPPP) program, bilateral contracts between IPPs and consumers (enabled by the amendment of Schedule II of the ERA) and international trade. The REIPPP program established a set price at which the electricity produced would be bought by a state representative body for a specified number of years through power purchase agreements (PPAs) with successful bidders. These facets of the current generation landscape necessitate the mitigation of

Eskom Generation's market power and the honoring of the contractual terms of the PPAs negotiated with IPPs as part of the transition to a market environment.

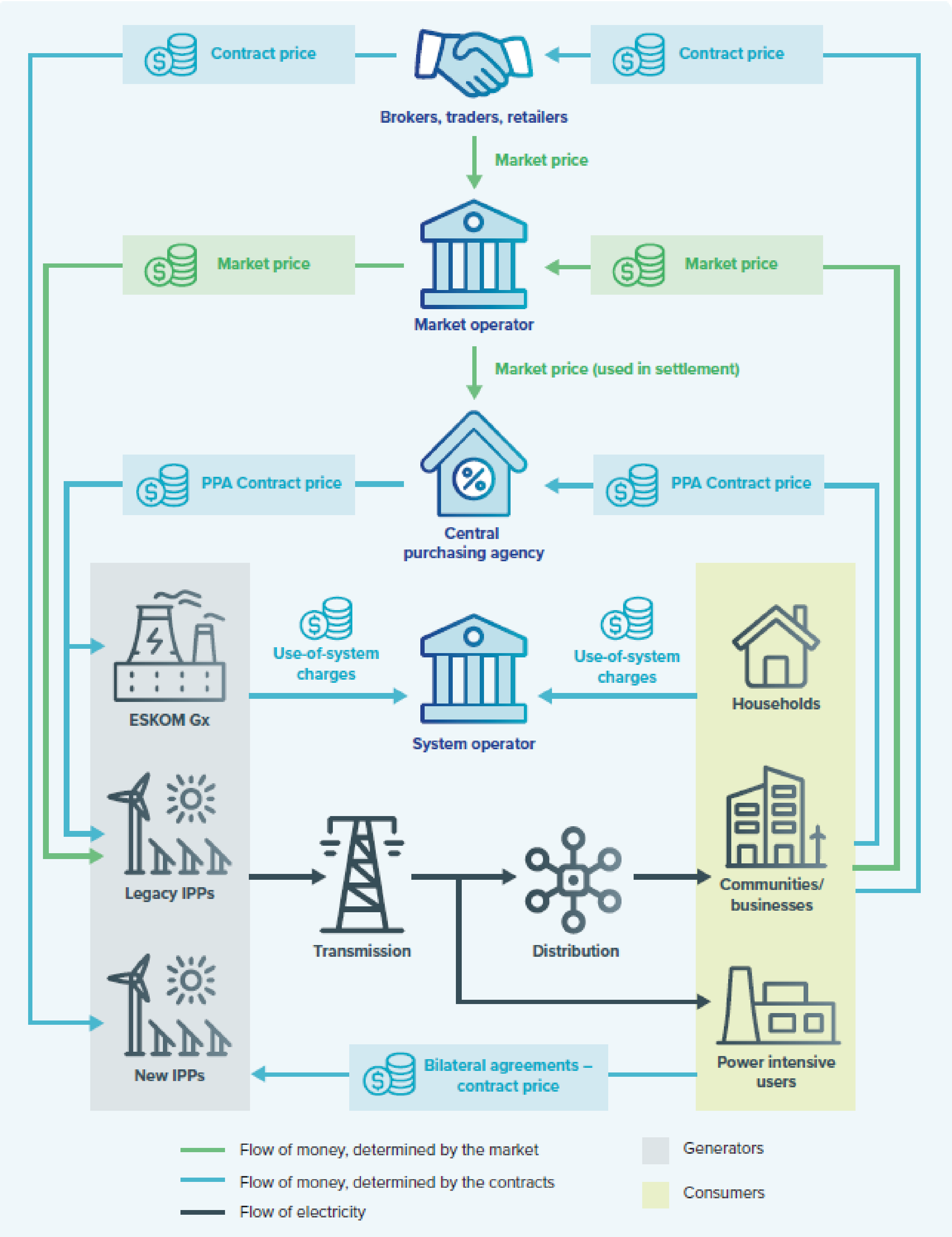

Figure 2. Participants in the South African electricity supply industry

It is worth noting that the current allowable transactions within the electricity industry mean that, in effect, a multimarket of sorts is already in place, though the institutional arrangements don't allow for good system visibility or cost-based optimization. A centralized market platform allows for these issues to be addressed, in addition to sending market driven price signals to the industry to determine when (and where) new generation capacity is created. Figure 2 shows a schematic of an electricity supply industry (ESI) with a competitive market.

Where these market mechanisms are deemed to be insufficient to ensure security of supply, capacity market mechanisms can be introduced to ensure long term system adequacy.

While competition will be allowed between **generators**, **transmission** and **distribution** networks must be operated and regulated as monopolies. This would still apply even with private participation in transmission expansion. This is because access to these networks is required by all participants and therefore non- discriminatory third-party access must be ensured as a prerequisite to competition. To cover the costs of owning, operating and expanding the network, an unbundled **use-of-system** tariff (sometimes referred to as a **wheeling** tariff) is applied to all electricity transferred on the network. This charge is paid to the **System Operator**, who is responsible for the metering of all market participants, the real-time balancing of supply and demand on the integrated power system and the issuing of dispatch instructions. In a competitive market environment, the System Operator will use orders from the **Market Operator** to manage the real-time processes required for the physical balance of the power system. The **consumers** (often represented by **traders**, **brokers and/or resellers**) will buy electricity from a chosen supplier that will utilise the various trading opportunities through the markets to buy electricity to meet the requirements from the consumers. The **Market Operator** is responsible for managing the market platform(s) and for ensuring that financial settlements between buyers and sellers are settled in a fair, neutral and transparent manner. In the next chapter, we will unpack the different market concepts and platforms proposed by the Market Operator.

4. Market concepts & platforms

In a balanced system, the amount of electricity produced equates to the amount of electricity consumed at any given time. The benefit of a market is not only that it allows consumers to choose products that best suit them but that in doing so, this system balance occurs at a price that is acceptable to everyone (defined as **market clearing**).

Given the coordination required to achieve this balance, different market mechanisms are used to facilitate it. These include market platforms in which:

a) predicted supply and demand is traded by participants ahead of time, to allow for system planning and coordination = short-term physical markets such as the **Day Ahead markets** and **intraday markets**

b) any imbalances created due to the difference between real and predicted supply and demand are reconciled to ensure system security = **balance responsibility, reserve markets** and **ancillary services.**

c) contracts can be entered into to provide capacity for longer term supply security = **capacity remuneration schemes**

d) the market model allows for **longer-term bilateral trades (both physical and financial)** to be traded directly between a buyer and seller outside the short-term physical markets to allow for hedging against price risk**.**

The **short-term physical energy market**, where electricity is paid for as consumed, consists of a commitment to the delivery and consumption of power. A future **financial energy market** allows for trading to occur on contracts, with an underlying reference to the short-term market. This market can be used for derivative trading, to support risk management strategies by participants. (For more details please see Appendix II).

The products that are the basis for the current market code to be operated by the Market Operator are illustrated in Figure 3.

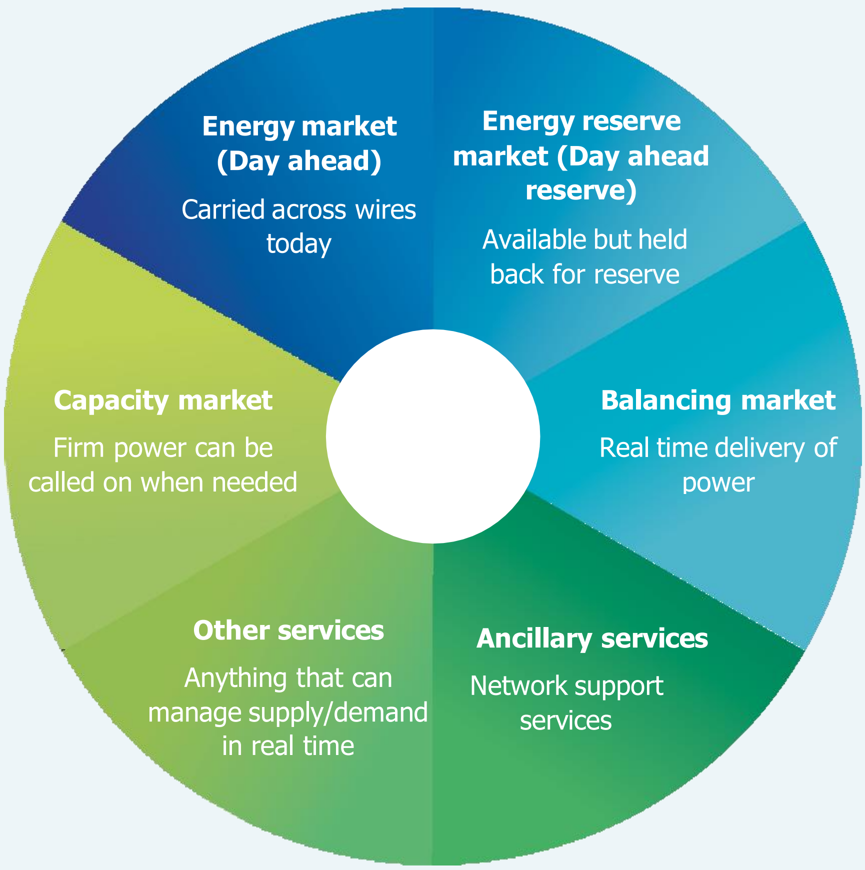

Figure 3. Overview of the South African multi-market model

Eligible buyers and sellers are also allowed to conclude physical and financial bilateral contracts directly outside these organised markets. These physical contracts, incorporating the commitment for delivery and consumption of power, will result in declarations to the Market Operator prior to the Day Ahead market (gate closure).

4.1 Day Ahead and intraday markets

A **Day Ahead market** is normally where most energy is traded. As the name suggests, the Day Ahead market is run one day ahead of real time and attempts to establish a provisional hour-by-hour balance between electricity supply and consumption. Generators submit a bid to the Market Operator for each of their power producing units, declaring their capacity, availability, technical capabilities, and price for each hour of the following day. These unit-based bids are referred to as complex orders, as they include technical parameters (start-up or shut- down times, how fast a unit can change its output, minimum generation etc.) and the prices associated with production as a capacity-dependent curve. Retailers, brokers and traders representing the consumers (households, businesses and power-intensive industries) submit their predicted consumption levels per hour as demand orders to the Market Operator. Once generators have offered their capacity, expressed with different volumes at different prices, and consumers have indicated their willingness to pay for energy at a set of given prices, the Market Operator matches generators and consumers on an hour-by-hour basis. Matching generators and consumers in this way results in a provisional balance point, as indicated in Figure 4, at which electricity is sold at a **system marginal price (SMP)** for all parties. The power generation units are activated in an ascending order of their respective offer price, and as a result, the most economically efficient production units will be chosen first (**energy optimisation**).

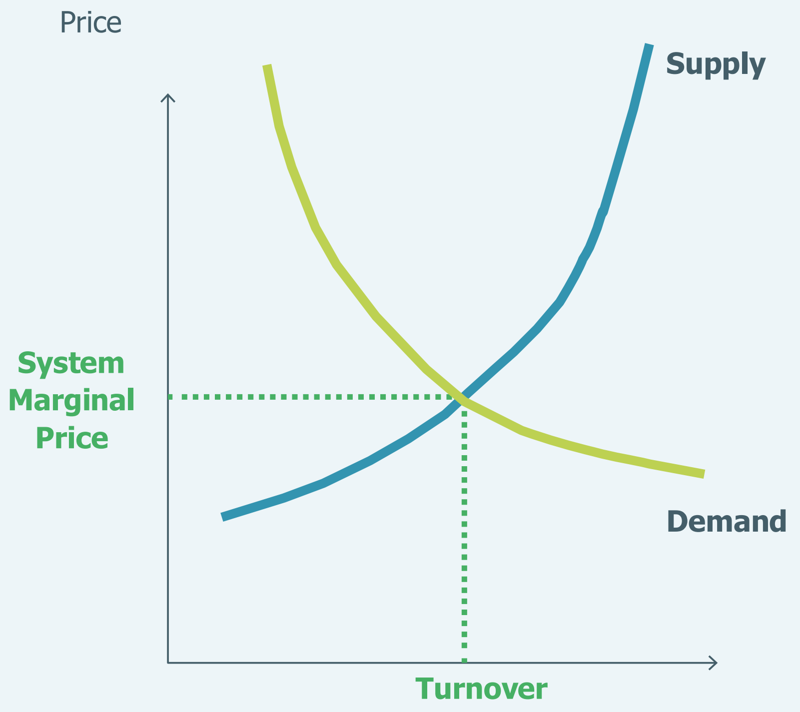

Figure 4. System Marginal Price and power volumes for both supply and demand curves

This initial market balance point is an **unconstrained result**, independent of any physical network constraints. However, the inclusion of network constraints is necessary to ensure the physical viability of the dispatch orders. Therefore, the volumes of power to be produced by each generator are recalculated to incorporate network constraints (called a **constrained result**). If a party's unconstrained schedule is reduced due to this re-calculation, it will be allowed to keep its "**lost opportunity payment**" for the constrained volume.

Example to demonstrate lost opportunity payment

a) A generator offers a generating unit at a price of R500 for a given hour.

b) The unconstrained market result is that this generator should produce 50 MWh at a SMP of R700.

c) However, due to network constraints, its production schedule is reduced to 45 MWh.

The generator's financial settlement for that specific hour would then be:

Total payment	=	production payment + lost opportunity payment
	=	(electricity produced SMP) + (lost opportunity generator offer price)
Total payment	=	(45 MWh R700) + [(50MWh – 45MWh) (R700 – R500)]
	=	R31 500 + R1 000
	=	R32 500

The constrained result is then used by the System Operator to formulate dispatch instructions for the next day. In addition to a Day Ahead market, **intraday markets** (once introduced) can be used throughout the day to balance production and consumption. These markets function in the same way as Day Ahead markets but within a shorter timeframe with auctions take place every four hours.

1.1 Balance responsibility and ancillary services

If all parties adhere to their predicted production and consumption, the system remains in balance. However, there are inevitably deviations from predicted production and consumption and these imbalances are addressed through **balance responsibility, Day Ahead reserve markets and ancillary services.**

Balance responsibility is defined as a participant's obligation to pay the costs associated with any imbalance caused due to the difference between real and scheduled supply or demand; if a generator produces less power than scheduled or consumers consume more power than scheduled, the participant is required to pay the costs associated with procuring additional power and coordinating the balancing of the system in real time.

The power required to balance the system in real time can be procured through **ancillary services and Day Ahead reserve markets,** where generators declare that they are available at specified times to produce a certain amount of power, if there is a shortfall. These generators are compensated both for making themselves available on standby and for any electricity produced during this timeframe. Due to the higher dispatchability and system coordination requirement for this type of generation, the price of electricity on this market is also higher. Consumers can also declare that they are available at specified times to reduce consumption by a specified amount (demand response), for which they will be compensated for. The requirement for the amounts and types of reserves is a calculation that is done by the System Operator to ensure system security (**reserve optimisation**). The Market Operator is responsible for procuring these ancillary services on behalf of the System Operator. These balancing mechanisms create a cost incentive for all parties to predict and declare their power production or requirements accurately and adhere to their predictions.

4.2 Co-optimisation of energy and reserves

To facilitate the trading for each market, the Market Operator uses **individual unit-based complex orders** from **balance responsible parties** (BRPs) (on both the consumption and generation side) in **different markets**, to optimise for both cost and system security. This is split into two main processes: Energy optimisation and reserve optimisation. The energy optimisation, represented by the energy balance between supply and demand is solved using the Day Ahead and future intraday markets, while the reserve optimisation, according to the System Operator's requirements, is solved in the reserve market.

Both the energy and reserves optimisations are solved in one algorithm. This algorithm will be run by the Market Operator, using the same unit-based complex orders in both markets. The algorithm will calculate the optimal results for both the energy balance between supply and demand, and the System Operator's requirement for reserves as part of one process. Thereby the name co-optimisation, as it optimises both the energy balance and the reserve requirement as part of one process or algorithm. This co-optimisation is one of the key features that distinguishes the proposed South African market model from, for example, its European counterpart.

Example to demonstrate co-optimisation

This is a simplified example based on one inflexible demand-side requirement of 600 MW and one reserve requirement (in reality, there will be three) from the System Operator of 150 MW. There are no network constraints in this example.

Three generating units (GU) with the following (simplified) parameters are offered to the market:

GU1	(1) 300 MW, priced at R400/MW, non-flexible
	(2) 100 MW, priced at R500/MW, flexible
GU2	(1) 100 MW, priced at R600/MW, flexible
GU3	(1) 200 MW, priced at R550/MW, non-flexible
	(2) 100 MW, priced at R700/MW, flexible

If you do a pure energy market calculation, the result would be:

GU 1:	All its output would be taken (400 MW),
GU 2:	None of its output would be taken,
GU 3:	200 MW would be taken (Order 1),

and the SMP would be R550 (the price of the last unit used in a merit-order selection).

However, the co-optimisation will also need to consider the reserve requirement from the SO.

Based on the orders on the previous page, the selection process would therefore be:

Reserves (this requires flexible generation):

GU 1:	100 MW from Order (2)
GU 2:	50 MW from Order (1)

Energy (both flexible and non-flexible generation can be used):

GU 1:	300 MW from Order (1)
GU 2:	50 MW of its Order (1) (remaining after reserve selection)
GU 3:	200 MW of its Order (1) and 50 MW of Order (2)

Resulting in a SMP for energy of **R700/MW** (the price of the last unit used in a merit-order selection) and a SMP for reserves of **R300/MW** (based on the lost opportunity cost from being kept outside the energy market calculated as the difference between the lowest cost offered – R400 for order 1 for GU 1 and the SMP – calculated at R700/MW).

Payments would then end up as:

GU1	Energy 300 MW * R700 = R210.000
	Reserve 100 MW * R400 = R40 000
GU2	Energy 50 MW * R700 = R35 000
	Reserve 50 MW * R400 = R20 000
GU3	Energy 250 MW * R700 = R175 000
	No reserve payment

5. Central Purchasing Agency

5.1 Introduction

In addition to the market platforms introduced by the Market Operator, a market support entity will be introduced to fulfil the role of counterpart to the contracts necessary to facilitate the transition to a competitive market, as well as managing non-market agreements or services to enhance the functionality of the market. The **Central Purchasing Agency (CPA)** within the NTCSA will perform these support functions, with activities including:

a) Concluding **Power Purchase Agreements** (PPAs) with Eskom Generation power stations **(vesting contracts)**

b) Becoming the counterpart to existing PPAs with independent power producers **(legacy contracts)**

c) Trading all energy purchased under PPAs into the Day Ahead Market (DAM)

d) Concluding sales agreements with distributors

e) Procuring the ancillary services required by the System Operator.

It will be financially responsible for the existing Power Purchase Agreements with IPPs (**legacy contracts**) and will participate as a balance responsible party in the market for the electricity produced under these agreements. It can also enter into new PPAs with IPPs to enhance system stability.

In addition to contracts with IPPs, the CPA will serve as the financial counterpart for electricity generated by Eskom Generation (**vesting contracts**). These contracts are signed with each power plant and typically consist of two parts; the first applied over the lifetime of the plant and the second expiring over time. The first section specifies an agreed upon payment to cover the fixed capital, operational and maintenance costs required by the plant and special ancillary services such as black starting and islanding. The second section specifies a fixed energy and reserve capacity price (**hedge price**) to be applied at the start of the contract and the process by which this fixed price will gradually transition to the market price over time. When applying a hedge price, power is first bought or sold in a competitive market then hedged back to the agreed upon fixed price. Eskom Generation will be the BRP for all its generation.

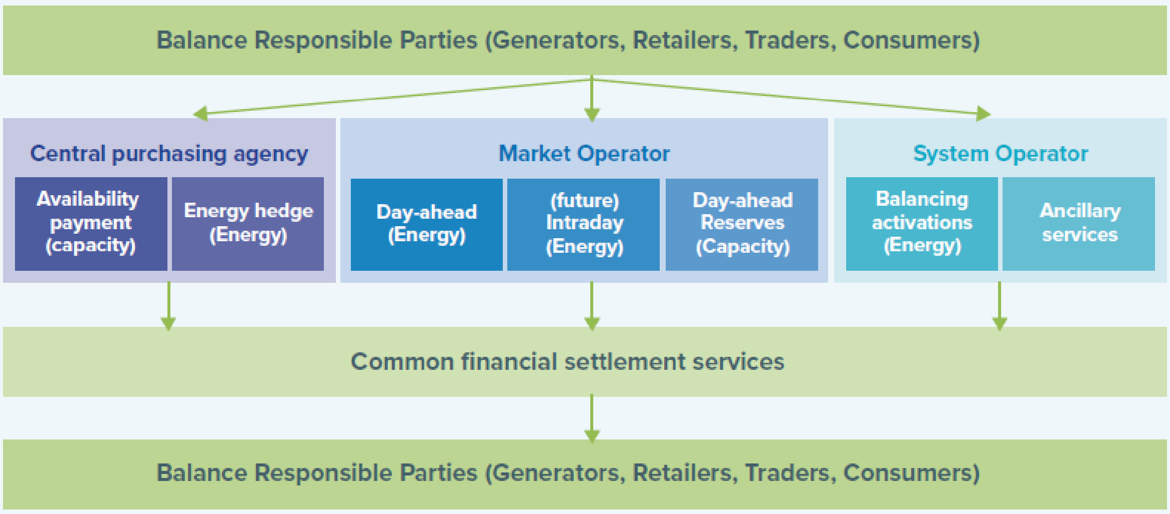

Figure 5. Organisational aspects of the market model

Figure 5 illustrates the resultant organisational aspects of the market model. The PPAs with Eskom Generation and Eskom Distribution are applied as per the agreed calculations and principles in these contracts. Currently, once these payments are determined according to the market, they are hedged back to a regulated revenue determination made by the National Energy Regulator of South Africa (NERSA).

Given that the CPA effectively serves as an intermediary between the market and several key participants, the extent of the shortfall experienced by the CPA on a monthly or annual basis is determined predominantly by the market price in the DAM for energy. A higher market price would reduce the shortfall with the agreed upon price and a lower price would increase it.

One proposal within the tariff unbundling process at the wholesale level is to create a **legacy charge** that would be payable by all consumers connected to the Eskom Transmission network, and by extension passed on by Distribution to customers connected to the Distribution network. The legacy charge could be applied either as a variable charge (c/kWh) dependent on energy consumed on the network, or as a fixed charge (R/kVA) dependent on either a notified maximum demand or actual maximum demand. A key component of calculating an expected legacy charge (which would be approved by NERSA as part of the Transmission network charges) would be to estimate the market price up front and adjust the legacy charge as part of an annual process.

5.2 Eskom Generation Vesting Contracts

If a competitive market were declared fully operational today, Eskom Generation would have such dominant market power that it would effectively have the ability to determine the price of electricity.

Therefore, the PPAs between the CPA and Eskom-owned power plants serves three purposes; firstly, to control the power Eskom Generation would otherwise have in the market, secondly to ensure the financial viability of these existing plants for the remainder of the plant life and thirdly to provide revenue for key services to support the South African grid.

The contracts are based on a standard agreement signed with each power plant, with specific regulations based on the technologies and cost structure of the respective generation facilities. The agreements shall be structured based on the assumption that the parties will not be part of the same company structure and will thereby fulfil all the legal requirements for a bilateral agreement between two independent entities.

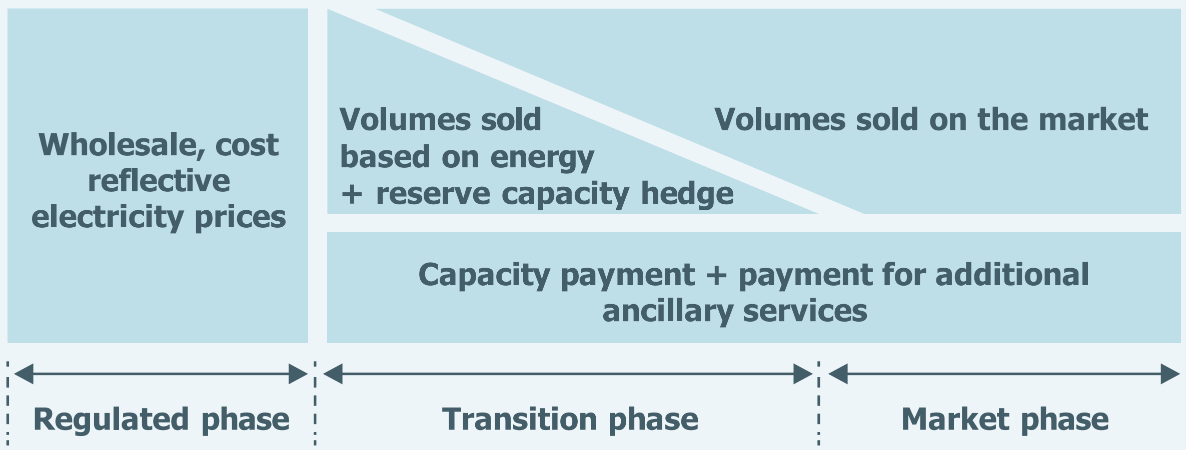

Figure 6. Schematic overview of the Eskom GX Power Purchase Agreements

A schematic overview of the PPAs with Eskom Generation power stations is illustrated in Figure 6. These PPAs will cover the following standard components:

- A **capacity payment** covering the fixed capital, operational and maintenance cost of the individual power station.
- An **energy hedge** that will (for a proposed stepwise period of five years) level the market price to an agreed upon energy price for a specified output. The stepwise period will progressively expose Eskom Generation to the market prices.
- A **reserve capacity hedge** that is similar to the energy hedge; agreeing on fixed prices from the start but moving towards market prices in the end. This hedge is a payment for capacity to be made available at short notice.
- Required additional ancillary services that cover special technical services for the System Operator such as black starting, islanding and other agreed pass-through costs.

In the following sections, further details on these components are defined.

Availability or capacity payment

An availability or capacity payment is one form of Capacity Remuneration Mechanism (CRM) (Appendix II). The key component of the availability or capacity payment will be an **Availability Rate**. The inputs to this are based on a set of key parameters:

- *Nominal Annual Capital recovery* (in Rand/annum)
- *Nominal Annual Fixed Maintenance recovery* (in Rand/annum)
- *Nominal Annual Fixed Operating Cost recovery* (in Rand/annum)
- *Nominal Annual Fixed Fuel Cost recovery* (in Rand/annum)
- *Expected Energy Availability Factor (EAF)*, based on an agreed annual availability factor for the power station's combined set of generating units measured monthly.

These figures are based on an individual assessment per power plant and are agreed upon by the CPA and the power plant. The parameters will be used to calculate a monthly Availability Rate expressed as a R/MW/h applicable to the power plant.

In addition to these direct input parameters, there are two more risk management elements that are used to calculate the Availability Rate:

- **An Availability Cone**, a specified allowable variation of the EAF due to over and under generation, to reduce risk for both parties and ensure a more stable financial output.
- **An Availability Penalty**, applied when power plants do not adhere to their declared availability in the market.

Energy hedge

The energy hedge is based on an agreed upon **annual average marginal** cost for the energy output of the units of the power plant, called an **Energy Rate**. The power plants are allowed to bid an incremental cost curve in the DAM, where the volume-weighted average price of the cost curve cannot deviate more than 30% up or down from the Energy Rate.

The power plant will be paid (or will pay) the difference between the Energy Rate and the average system marginal price (SMP) from the DAM. As with the availability payment, there is an upper and lower band of the payments covered by the energy hedge. This shall be specified as a monthly value in the agreement.

This is a way to agree on a fixed price (for example, based on a contract such as the PPA between the CPA and Eskom Generation), where the power is bought or sold in a competitive market and then hedged back to the agreed price. A generic mechanism that is employed in a lot of markets to facilitate such a hedge, also in energy markets, is called a **Contract for Difference (CfD)**. More information on CfDs can be found Appendix I.

Reserve capacity and other ancillary services

The **reserve capacity hedge** (Instantaneous, Regulating, and Ten-Minute Reserves) is applied in a similar way to the energy hedge. The requirements, selection and pricing of these reserves is done in the competitive market, but the PPA administers a hedge back to an agreed price for this service that is related to the Energy Rate.

In addition, a PPA typically covers various ancillary services with different technical requirements and different kinds of remuneration. Most of the ancillary services require various forms of prequalification such as required testing and certifications that are defined in detail. These ancillary services may include:

- **Black start:** starting a unit without external grid support;
- **Unit islanding*:*** continuing to power an area without external grid support;
- **Reactive power and voltage control:** power plants suppling or absorbing reactive

power as necessary to maintain voltage and stability on the transmission grid.

Last, but not least, the PPA covers the respective power plant costs incurred in starting up a generating unit when it has been placed in cold reserve mode by the System Operator, or due to market conditions until called up by the System Operator or in the market.

From time to time, some power stations could become a consumer. This could, for instance, happen when the plant is out for maintenance, but still has commitments to generate power. If so, their consumption is included as negative generation in the calculation of the energy sales covered under the energy hedge in section 3.1.2. The power station could also, in certain circumstances, consume energy for the purposes of auxiliary supply and other supply requirements. This energy may be purchased from a distributor through the customer billing system, or from the CPA. If this is under the PPA, the consumption points must be identified in the contract and the power station will pay the CPA for the power consumed per month at the same Energy Rate as agreed in this agreement.

5.3 Independent power producer legacy contracts

Additional capacity has been procured from **independent power producers** (IPPs) through multiple rounds of the **Renewable Independent Power Producer Programme** (REIPPP). The capacity requirements for this procurement programme were based on a ministerial determination by the Department of Mineral Resources and Energy, in line with the Integrated Resource Plans of 2010 and 2019. The counterparty to the contracts with the IPPs was Eskom. However, in a market environment, Eskom would no longer be the single buyer of electricity and would in fact be a competitor. Moreover, the price specified in these contracts is likely to be non-competitive on an open market, as it ensured a guaranteed rate of return for IPPs that created new capacity in a risky investment environment. Nonetheless, the obligation to honour the terms negotiated within those contracts remains.

The CPA will therefore manage and be financially responsible for the existing PPAs with IPPs (legacy contracts). The CPA will participate in the DAM on behalf of these generators for all the electricity produced under these agreements. The CPA will then become a market participant, but because of its central position during the transition it should not be able to be an active trading participant. Instead, the forecasts from the REIPPP and the dispatch costs will be submitted to the DAM and the CPA will effectively become a price-taker in the market. The IPPs will remain balance responsible for the forecasted output that will be sold via the CPA. This will ensure a managed migration to a fair and effective competitive market.

5.4 Concluding sales agreements with qualifying customers

Qualifying customers

Initially Eskom Distribution would be the only customer eligible to conclude a sales agreement in the form of a hedging contract. However, as this agreement is a complete bilateral agreement it can be used for any qualifying customer in the future. This contract has the same general structure as the Power Purchase Agreements for Eskom Generation.

Energy charge and hedging arrangements

A qualifying customer (initially Eskom Distribution) will pay for the power they consume at the SMP established in the market, based on their own demand forecast. As with the Eskom Generation PPAs, there is a hedge in place, where the buyer will have to pay the difference between the active energy charge of the wholesale energy prices (agreed upon price) and the weighted average SMP in that time-of-use period (market price). The wholesale energy price is currently the agreed tariff approved by NERSA. The qualifying customer will also be subject to imbalance charges (or payments) per the market rules. Lastly, this PPA also covers management of load shedding activities by Eskom Transmission, under system emergency conditions declared by the National System Operator.

Capacity charge

In addition to the energy charge outlined in the previous section, a capacity charge is applied. A qualified customer is charged a capacity charge based on their maximum consumption in any hour of the previous 12 months (essentially a maximum demand charge). The charge is the maximum demand rate (currently set as the amortised hourly fixed cost of a combined cycle gas turbine plant) number of hours in the month. There is also a capacity rebate applicable where load shedding events have been issued.

5.5 Future capacity assessment and procurement

The CPA is also tasked to develop indicative generation expansion plans, which are published to inform market participants. The CPA will monitor the market for capacity delivery against these plans and embark on procurement if projected capacity requirements are not being realised by the market. It is expected that over time, supply and demand will become more closely aligned and that there will be no need for the CPA to manage this, but this function will likely be needed in the short to medium term. It provides a fall-back position, to ensure the System Operator has resources to meet real-time demand at any point in the medium- to long-term view.

Once the generation expansion plan is agreed upon, there are two generic options to procure this capacity:

- A form of Capacity Remuneration Mechanism (CRM)
- An energy hedge contract (Contract for Difference)

The main difference between these two support mechanisms is that in a CRM, you pay for the capacity to be available, while in an energy hedge (or Contract for Difference) you are guaranteeing a price for the power that is being sold in the markets.

In addition to the procurement of future energy capacity, the CPA is tasked to perform the required long-term ancillary services on behalf of the System Operator, either incorporated into capacity contracts or as stand-alone ancillary service agreements.

5.6 Potential future additions

It is expected that the functions of the CPA could be extended to other tasks over time. A potential addition to the function of the CPA is that it could serve as the procurer of power for vulnerable customers (that is, non-paying). This would have to be funded through governmental support, but then the CPA could act as a buyer of this power in the market, ensuring that the generators and distribution network operators (DSOs) or transmission system operators (TSOs) that provide the service get paid.

6. International trade

In addition to the internal South African markets, the market model also needs to take into account how trading is conducted in the **Southern African Power Pool** (SAPP). The international trade concept is still under development and thus the following presents the most recent version of the concept. International trade covers both bilateral trading with the regional counterparts and the trade in the organised markets governed by SAPP.

The objective of the concept is to ensure that the regional trade is performed in such a manner that it brings benefit to the South African power sector, ensuring participation based on sound economics.

A generic requirement for all parties that shall be trading on SAPP is that they hold an export license in South Africa and that they are a market participant in the SAPP markets. Any party participating or interacting in the SAPP markets will be under SAPP governance as well as the South African Market Code. The CPA shall manage and maintain the historical regional bilateral contracts and schedule these according to the SAPP Market Book of Rules. The following Parties will interact with SAPP markets:

System Operator

- Provides the available transmission capacities for all international interconnections from South Africa to the SAPP markets;
- Acts as a Transmission System Operator under the SAPP regulations;
- Nominates the total scheduled flows to the Market Operator;
- Acts as the balance responsible party towards SAPP.

Market Operator

- Represents (trading proxy) the South African market participants for those volumes that are traded through the South African market;
- For the Day Ahead market, creates a Net Export Curve representing the aggregated purchase and sales offers from the orders in the South African Day Ahead market, using the order information from the different market participants, including adjusting for any capacity payments;
- For the SAPP intraday and balancing markets, makes available national orders according to a set of detailed rules;
- Takes the scheduled flows from the SAPP markets as a deemed flow in the market clearing in the South African market.

South African market participant with a capacity payment agreement with the CPA

- Shall always offer their full capability to the national market of South Africa and will not be allowed to participate directly in the SAPP regional markets;
- Will indirectly be participating through the Market Operator, which will use its orders in the short-term markets (Day Ahead market, intraday market and balance market) and thereby have implicit access to the regional markets.

South African market participant without a capacity payment agreement with the CPA

Has a choice regarding who it will buy from or sell its requirement to in a market, and thus can buy or sell power through the following channels:

- A bilateral physical contract with a South African counterpart: In this event, the participant will have to nominate its planned schedule to the Market Operator to be considered in the South African market. The bilateral contract will be settled between the parties.
- A bilateral financial contract with a South African (or regional) counterpart: In this event, it should participate in the South African market to secure a physical position. This financial bilateral contract will be settled between the parties.
- Subject to being a SAPP market participant: Participate in the SAPP organised physical

markets. If successful, nominate its schedule to the System Operator to be considered in the management of the transmission capacity towards SAPP. The settlement of this trade will be towards SAPP.

- Participate in the South African short-term physical market as a market participant under the South African Market Code; or
- Any combination of the above.

7. Conclusion

In conclusion, the proposed liberalisation and ongoing unbundling of Eskom represents a significant change in the historic landscape of the South African ESI. To manage this transition to a competitive wholesale market, the introduction of market platforms (such as the Day Ahead, intraday, reserve and ancillary services market) and participants will need to be implemented gradually over time. In addition, the Market Operator, System Operator and CPA will have critical roles to play, to facilitate the functioning of a market.

8. Further reading

DMRE (Department of Mineral Resources and Energy) Electricity Regulation Amendment Bill *published in Government Gazette No. 48441 of19 April 2023*. Available at: https://www.gov.za/sites/default/files/gcis_document/202308/b23-2023electricityregulation.pdf

DPE (Department of Public Enterprises) (2019) *Roadmap for Eskom in a Reformed Electricity Supply Industry.* Available at: https://dpe.gov.za/wp-content/uploads/2019/10/ROADMAP-FOR-ESKOM_0015_29102019_FINAL1.pdf

Appendix I: Contracts for Difference

I.1 The basics of Contracts for difference and financial energy markets

To understand the function of a Contract for Difference within an energy context, one must first make the distinction between a **physical energy market / contract** and a **financial energy market / contract.** In a physical energy market, such as a Day Ahead and intraday energy market, trading entails a commitment for the delivery and consumption of electricity. Generators enter bids for the volume of electricity they are willing to produce at a certain price and consumers enter bids as to how much they are willing to pay for a specified amount of electricity. A co-optimisation algorithm is then used to match generators and consumers, thereby determining a market price at which the electricity is sold. (For more details on these market mechanisms please see Chapter 4).

In a financial energy market, parties do not have to hold or trade the underlying physical commodity itself (in this case electricity), but rather trade based on the changing value of the underlying commodity (the derivative) using the physical energy market as the reference point. A financial energy market thus functions in much the same way as a stock market. CfDs have a long history as a mechanism of trading in financial markets. A CfD is a financial derivative contract between two parties, where the parties settle based on the price difference between an agreed upon price (strike price) and the underlying market price in the reference market (reference price).

This type of contract can be implemented as an agreement between

- two market participants (on a bilateral basis as a substitute for a physical bilateral contract)
- a market participant and a central counterparty / marketplace, or
- two market participants via a central counterparty / marketplace.

A common setup in energy transitions and government subsidy schemes is a central counterparty such as a government agency or a government fund acting as the counterparty to the CfD. This allows the other party to the contract to reduce exposure to the volatility of energy prices in short-term physical market(s).

There are two categories of CfDs: **two-way** and **one-way** CfDs. A **two-way CfD** is a contract where the direction of payments within the CfD depends on whether the difference between the strike price and reference price is negative or positive. The effect is that in all circumstances, both the buyer and seller will pay or get paid the strike price. The effective outcome of CfDs is that after both the physical wholesale market and the CfD contract are settled, the combined amount both parties have paid / have been paid adds up to the strike price multiplied by the agreed volume. Such a mechanism creates security and stability in the form of a long-term fixed energy price for both parties, while increasing liquidity due to their participation in the short-term physical wholesale market. This is the most common implementation of CfDs and there are many examples of the implementation of financial derivative markets for electricity, where these contracts are offered as standardised products to trade.

By comparison, in a **one-way CfD** payments are one-directional and in the case of the reference price being higher than the strike price, no payments are made. This ensures a minimum price for the seller and allows it to keep its profit if the reference price is higher than the strike price. As an example, in a certain support scheme for renewable energy sources (RES), a generator benefits if the market price exceeds the strike price.

Figure 7 illustrates how the payments in these two types of CfDs will be facilitated from the point of view of a generation company. The left side diagram of the figure presents a scenario with a two-way CfD. In this scenario, if the market price is lower than the strike price (hours 1–3 and 7), the generator receives income from the market (dark blue) according to the market price (lime green), and the CfD counterparty pays the generator for the difference between the strike price (yellow) and the market price (dark green). If the market price is above the strike price (hours 4 and 5), the generator must pay back the difference between the strike price and the market price. If the market closing price is equal to the strike price, no payments outside of the market are made (hour 6). Chapter 4.3 presents a practical numerical example of how the turnover from a two-way CfD would be calculated compared to a Power Purchase Agreement (PPA).

Figure 7. Example of payments under a CfD

The right-hand-side diagram in Figure 7 presents a one-way CfD, where the difference to a two-way CfD is that when the market price exceeds the strike price, the generator gets to keep this difference between strike price and market price as extra revenue from the wholesale market. It should be noted that CfDs can be settled either at the same time resolution as the underlying market or less frequently and based on either hourly market prices or average prices. In the examples of Figure 7 the settlement is on hourly market prices.

I.2 Contracts for Difference as regulated schemes

The length of CfD regulated schemes can vary greatly. In some cases, support schemes may be tied to regular (for example, biannual) reviews, where the regulator determines if the CfD is still appropriate based on new developments in the market. A CfD can cover a specified amount of energy produced or consumed, or all the energy the generator is able to produce. In transitory measures for market deregulation and energy transitions, the CfD might be tailored so that the energy contracted decreases annually to give the parties a smooth transition into a fully competitive market and pricing.

Depending on the purpose of the CfD, there are several ways the strike price can be set or agreed upon. A government can administratively determine a strike price based on benchmark values such as an estimated cost of new electricity generation and the price of carbon emissions. Arranging an auction to get the best competitive strike price is also common in schemes that are intended to incentivise new capacity. Alternatively, the parties to a bilateral CfD can agree on a price based on their expectation of future developments in the market price.

CfDs are an effective way to move trade from bilateral physical contracts onto a short-term wholesale physical market. Typically, when introducing CfD schemes to support market opening, some concerns are raised as to whether the contracted parties distort the market with the guaranteed price from the CfD (which might be seen to disincentivise bidding in a competitive way). Despite CfD covered generators being compensated for their production, there are several reasons why the incentive to bid competitively still exists.

Firstly, the CfD premium will cover only the shortfall between the market price and strike price. In other words, in a case where a CfD covered generator bids an artificially low price, they would get compensated based only on the overall market closing price and thus wouldn't gain from bidding artificially low (or high). Secondly, in competitive power markets the generators always aim to maximise their profits. Bidding on artificially high prices might result in the generator not being scheduled, missing any profit from that day. Thirdly, and most importantly, bidding at a considerably lower price level than what is justified, without a clear need to do so, amounts to market manipulation, which is prohibited in market rules.

I.3 Potential applications of Contracts for Difference in a South African context

CfDs are used for various purposes, and the design parameters of the contracts can be tailored to suit policy needs. Table 1 presents various common applications of CfDs.

Table 1. Different applications of Contracts for Difference

Application	Explanation	Main benefit
Tool used by government in energy market liberalisation	When a wholesale electricity market is newly established, CfDs can be set up solely for the purpose of hedging the prices for an initial period for the generators and retailers who are not yet accustomed to the mechanics of the wholesale market. When imposed at the time of deregulation or transition, this is often referred to as **vesting contracts.**	Introducing participants to the market without exposing them to the full risk of volatile prices from the start, while retaining price signal from the market
Tool used by government to incentivise investment into desirable technologies	Emergent technologies are typically more expensive as the value chain is not yet fully developed. Many renewable energy support schemes around the world rely on CfDs or similar mechanisms to guarantee prices for newly installed renewable energy capacity.	Incentivising investment into desirable technologies and increasing market liquidity
Curbing the exercise of market power	A government can enforce mandatory CfD schemes on dominant market participants, to reduce their market power. Guaranteeing a price with a CfD, for a certain amount of production during scarce supply, will discourage a producer from misusing its market power, to withhold capacity.	Reducing incentives to use market power
Replacing physical bilateral contracts	A CfD can be used instead of a physical bilateral contract. Instead of paying an agreed upon price for an agreed upon volume of electricity, the parties to the contract sell and procure their electricity on the organised markets, with the CfD providing financial certainty.	Increasing market liquidity, introducing participants to the market without exposing them to the full risk of volatile prices from the start, revealing the marginal price of the system

Appendix II: Capacity remuneration mechanisms

Generally, capacity payments are a term that encompasses a lot of different potential measures. Therefore, these are more generically referred to as **capacity remuneration mechanisms** (CRM). The market-wide capacity mechanism for South Africa has not yet been decided. Typically, capacity mechanisms are based on a requirement to solve a specific issue. For instance, the capacity payments (or availability payments) that are part of the Eskom Generation PPAs are simple capacity payment solutions, where they intend to cover for the PPA holders' fixed capital, operational and maintenance costs. Based on a declared availability, Eskom Generation will get paid for these costs through the PPAs.

This type of trading activity is used to ensure electricity supply on a longer-term basis. The determination of the requirements to ensure supply stability is performed by the System Operator, who calculates the requirements for both the total capacity and strategic reserve. Market participants can then agree to make existing capacity available for a fee (capacity payments and **strategic reserve schemes**) or enter into contracts to build new energy infrastructure for an agreed upon price (**capacity auction schemes**), with the cost of remuneration for the capacity market borne by the consumer.

Capacity payments can be made to both consumers who reduce their demand and generators who increase their supply of electricity. A wide spectrum of options exists for these payments, categorised according to several factors, including the kind of capacity being made available, how far in the future the obligations span and how the payment costs are determined and allocated. In a strategic reserve scheme, some generation capacity is set aside to ensure security of supply in exceptional circumstances, which can be signalled by prices in the Day Ahead, intraday or balancing markets increasing above a certain threshold level. The capacity to be set-aside is procured and the payments to the generators determined through a (typically year-ahead) tender. The security of supply can also be addressed through **capacity obligation schemes**, which places an obligation on big generators or consumers to make capacity available at certain times or face penalties. Lastly, availability of existing capacity can be addressed through a **reliability option**, a mechanism in which contracted generators agree to cap the price at which they sell electricity. This effective cap is implemented by generators paying the System Operator the difference if the market electricity price exceeds a reference price. Importantly, the difference between the agreed upon price and reference price has to be paid by the generator, whether they are producing electricity at that time or not. This creates an incentive for the generator to produce electricity at times of scarcity when the price of electricity is high, because if they didn't, they would have to pay the difference without any revenue from the sale of electricity. In return, the generator benefits from a guaranteed stable income stream.

In **capacity auction schemes,** participants bid for contracts to build new energy infrastructure at a price determined through an auction process. Potential investors benefit from both a guaranteed return on investment and an upfront payment, while the market benefits from ensured capacity and stabilised prices. Without this type of CRM, price signals would dictate when generators invest in new energy infrastructure; when there is limited electricity supply, prices go up and it becomes more profitable to sell electricity. In this scenario, generators take on more risk, because if the price of electricity goes down while they are still building new capacity, they stand to make a loss. However, the potential reward is also higher, because if the price of electricity becomes very high, they stand to make more profit. In either scenario the cost is borne by consumers; CRMs spread these costs out over time to reduce price volatility but may result in a higher overall payment.