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Integrating market and bilateral power trading in the Southern African Power Pool

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Abstract: High levels of inflexible bilateral trade in southern Africa have limited the participation in the competitive short-term markets, leading to inefficient use of energy infrastructure and blocking the Southern African Power Pool's long-term goal of transitioning from a cooperative to competitive market. Under the current supply and investment climate, governments and market participants are unlikely to forego their preference for long-term contracts owing to concerns about security of supply and risk mitigation. In this paper, we demonstrate that the current method for integrating bilateral and market trading introduces inefficiencies in the use of generation and transmission infrastructure, reduces total trade, and increases system costs. We propose and test an alternative method based on contracts for differences and implicit auctions to ensure the same level of security of supply for contract holders while minimising market distortions.

Keywords: bilateral contract, market design, power pool
JEL classification: C61, O21, Q40, R58

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1 Introduction

The Southern African Power Pool (SAPP), created in 1995 by 12 member nations of the Southern African Development Community, is the oldest and only operating power pool in Sub-Saharan Africa. The mission of the SAPP is to 'provide the least cost, environmentally friendly and affordable energy and increase accessibility to rural communities' (SAPP, 2015:2). More specifically, the regional market was developed to meet the following goals:

- improve security and quality of electricity supply;
- capture economies of scale for larger generation plants through pooling of demand;
- reduce prices to consumers through increased competition among market participants and economies of scale in generation;
- increase power accessibility in rural communities; and
- facilitate the development of regional expertise through training programmes and research.

Since its inception, the SAPP has struggled to transition from a cooperative to competitive market (Musaba, 2010). Regional trade is dominated by long-term bilateral contracts, accounting for 94% of total trade in 2014–15 (SAPP, 2015). Proponents of the competitive market argue that these contracts result in higher prices for consumers compared with competitive market prices, pose a barrier for new entrants by limiting trading opportunities, and do not promote the efficient use of energy resources or energy infrastructure.

At the same time, concerns about security of supply have led governments and market participants to prefer long-term contracts. Insufficient investment in new generation and transmission infrastructure has left the region with supply shortages, and both consumers and producers see long-term contracts as a means of reducing supply and demand risk for themselves. In addition, bilateral contracts have long been viewed as necessary in the region in order to obtain financing for investments in new power plants or energy-intensive industries (Zhou, 2012).

In this paper, we evaluate the current method of integrating bilateral contracts with competitive market trades. Specifically, we develop a representative economic dispatch model of the SAPP to analyse the impact that contracts have on trade flows, system costs, generation, and security of supply. We propose and test an alternative approach to integrate bilateral and market trading that ensures the same level of security of supply while minimising efficiency losses observed with the current treatment of bilateral contracts.

Section 2 provides background information on the current structure and operation of the SAPP. Data and methodology are presented in Section 3. Section 4 gives the modelling results of bilateral contracts on the regional market using the current SAPP rules. In Section 5, we propose and test an alternative approach to integrating bilateral and market trades and, finally, Section 6 provides a discussion of the findings and study conclusions.

2 Background

2.1 SAPP overview

The SAPP is composed of 16 utility members from 12 countries. Membership is divided among operating members, those physically interconnected to the regional grid, and non-operating members who are not interconnected (Table 1). South Africa is the most influential country, accounting for almost 80% of demand and 75% of generation capacity.

Table 1: Southern African Power Pool (SAPP) membership

Utility	Status	Abbreviation	Country
Empresa Nacional de Electricidade	NP	ENE	Angola
Botswana Power Corporation	OP	BPC	Botswana
Societe Nationale d'Electricite	OP	SNEL	Democratic Republic of the Congo
Lesotho Electricity Corporation	OP	LEC	Lesotho
Electricidade de Mocambique	OP	EDM	Mozambique
Hidroelectrica de Cahora Bassa	IPP	HCB	Mozambique
Mozambique Transmission Company	ITC	MORTRACO	Mozambique
Electricity Supply Corporation of Malawi	NP	ESCOM	Malawi
NamPower	OP	NamPower	Namibia
Eskom	OP	Eskom	South Africa
Swaziland Electricity Company	OP	SEC	Swaziland
Tanzania Electricity Supply Company Ltd	NP	TANESCO	Tanzania
ZESCO Limited	OP	ZESCO	Zambia
Copperbelt Energy Corporation	ITC	CEC	Zambia
Lunsemfwa Hydro Power Company	IPP	LHPC	Zambia
Zimbabwe Electricity Supply Authority	OP	ZESA	Zimbabwe

Notes: NP, non-operating member; OP, operating member; IPP, independent power producer; ITC, independent transmission company.

Source: SAPP (2015).

Security of supply is a critical issue in the SAPP. In fact, three of the market's six objectives are related to improving security of supply and regional coordination in developing energy resources. When the regional market was formed in 1995, most countries were struggling to meet domestic electricity demand while South Africa and the Democratic Republic of Congo (DRC) had 2160 and 1984 MW of excess capacity,[1] respectively. Cross-border trade and regional coordination represented a way for member countries to capitalise on excess supplies. Since the SAPP's formation, these surplus supplies have diminished steadily and the SAPP has experienced capacity deficits since 2007. At the start of 2015, the SAPP had a shortfall of 8000 MW of available capacity during peak demand periods (17% of peak demand). Years of supply interruptions continue to have a tangible impact on the region's economic development. In 2014, 11 out of 12 SAPP countries were ranked among the bottom 50 in the world for quality of electricity supply according to the World Economic Forum (Schwab, 2014).[2] With insufficient supplies of excess power to trade, investments in cross-border transmission capacity are less attractive and have fallen short of what is needed to facilitate cross-border trade.

[1] Regional reports do not specify if these numbers refer to installed capacity or firm capacity. What is clear is that both countries had sufficient capacity to meet domestic demand and were pursuing economic opportunities to export surplus generation.

[2] Namibia is the sole exception with a score of 52 out of 148 countries.

2.2 Energy trading and dispatch

SAPP members can choose from three trading arrangements:

- Long-term bilateral contracts
- Short-term or over-the-counter (OTC) bilateral contracts
- Day-ahead market (DAM), intra-day market (IDM) trades.

Long-term bilateral contracts are the basis for cross-border trading in the SAPP. These contracts can be firm or non-firm. OTC bilateral contracts are mainly entered into on a needs basis to meet short-term demand. These arrangements are <1 month in duration, can be firm or non-firm, and do not require a formal power purchase agreement. An auction-based 'forward physical market' is a firm short-term energy market and is expected to replace OTC trades once it is fully operational. The DAM is a firm energy market designed to optimise the use of generation and transmission resources. The SAPP market operator (MO) runs the DAM in intervals of 24 hours. The IDM provides 'an opportunity for members to rearrange their bids and offers if they failed to trade in the DAM or trade any power that became available after the DAM was run and closed' (SAPP, 2013a:24).

The SAPP MO is responsible for collecting all trading information from bilateral and market trades and scheduling power exchanges between control areas.[3] This process occurs over a series of steps. In the morning the day before trading, parties with bilateral contracts declare their trades and wheeling paths, confirmed by the transmission system operators, to their local control area system operator. The control area operators combine these declarations to calculate the remaining cross-border transmission capacity available for market trading. This information, along with information on all self-scheduled bilateral trades, is sent to the SAPP MO.

On the basis of these declarations, the SAPP MO calculates and publishes the remaining transmission capacity available for DAM trading. Participants use this information to submit their offers and bids for the DAM. At noon, the DAM closes and the SAPP MO publishes the results including traded volumes, power requested, market clearing prices, and any remaining demand and transmission capacity available. Participants can then contest any errors or resubmit their bids to the IDM, which opens immediately when the DAM results are published.

On the day of trading, each control area system operator is responsible for monitoring and correcting intra-control area imbalances of supply and demand. The SAPP Coordination Centre handles inter-control area imbalances according to procedures described in the SAPP Operating Guidelines (SAPP, 2013b).

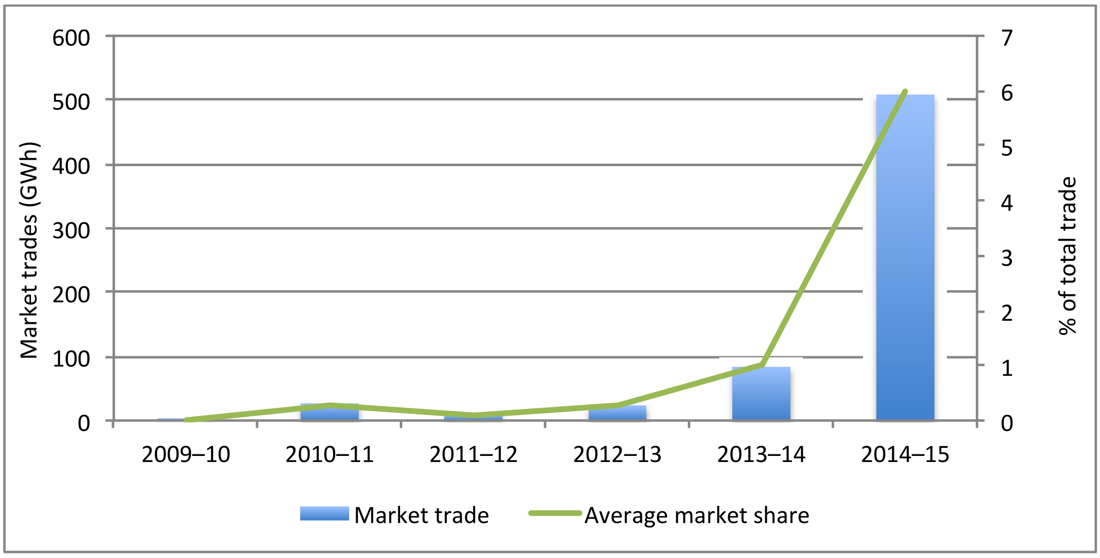
[3] The SAPP is divided into three control areas, each with its own control area system operator. Eskom serves as the operator for Botswana, Lesotho, southern Mozambique, Namibia, South Africa, and Swaziland; Zimbabwe Electricity Supply Authority (ZESA) is the operator for Zimbabwe and northern Mozambique; and Zambia Electricity Supply Corporation (ZESCO) is the operator for Zambia and the DRC.

2.3 Market performance

Since the DAM opened in 2009, market participants have relied primarily on bilateral contracts for cross-border power exchanges rather than competitive market trading. The share of cross-border trade with bilateral contracts has shrunk in recent years but still remains above 90% (Figure 1).

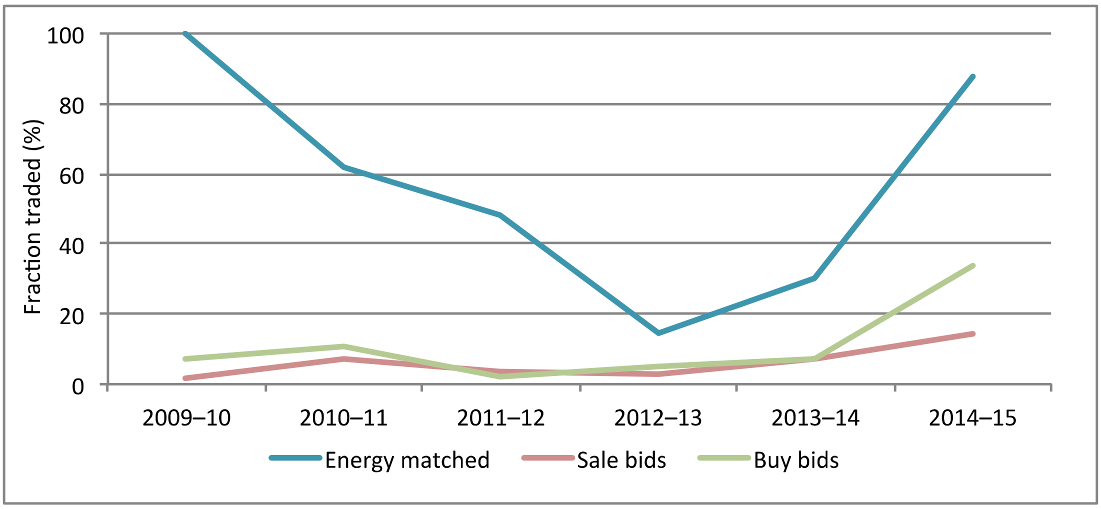
Bilateral contracts are favoured among power purchasers because they provide guaranteed electricity supply during scarcity events. For producers, the favourable treatment that contracts receive during the dispatch process ensures they will have priority access to the transmission network to sell their power. By contrast, DAM and IDM traders face high levels of uncertainty as to whether their bids will be matched in the market and, if matched, whether the trades will be technically feasible as a result of transmission constraints. Figure 2 shows the fraction of DAM and IDM bids and matched energy that was actually traded. Historically, <20% of buy and sell bids submitted to the SAPP MO were matched in the DAM or IDM. Among the offers that were matched, only a fraction was actually traded because of transmission constraints. In the most recent trading year, 88% of energy matched in the DAM or IDM was traded, a significant improvement from only 15% in the 2012–13 trading year.

Figure 1: Growth in market trading (DAM+IDM) as a fraction of total cross-border trade



Source: Authors' illustration based on SAPP (2010, 2011, 2012, 2013c, 2014a, 2015).

Figure 2: Fraction of submitted bids and matched trades that are actually traded



Notes: Historically, <20% of sale and buy bids offered on the market are traded. For bids that are matched, not all of these trades take place owing to transmission constraints.

Source: Authors' illustration based on SAPP (2010, 2011, 2012, 2013c, 2014a, 2015).

2.4 Study objectives

International experience in the United States and European markets suggests that bilateral contracts do not have to conflict with market efficiency. In fact, Hogan (1994) argues that bilateral transactions need competitive markets for balancing and economic efficiency and competitive markets need bilateral transactions to provide market stability for the majority of trading activity. However, these transactions are only complementary if commercial bilateral transactions do not influence the least-cost dispatch and delivery of energy – a condition not met in the SAPP's current market design.

Proposed solutions for promoting both market competition and security of supply in the SAPP have focused on investing in new generation and transmission infrastructure and encouraging market participants to shift from bilateral to market trading through regional training and information programmes. New investments are slowly coming online but current projections indicate the system will be constrained for many years to come. Even if supply constraints are eased through new infrastructure, it is not clear that members will be willing to abandon long-term contracts in favour of market trading. More importantly, however, SAPP members do not need to abandon bilateral contracts to promote efficiency gains from the competitive market. Instead, the SAPP must address the underlying market design flaw that puts bilateral transactions in conflict with market efficiency.

To date, evaluations of the impact of bilateral contracts in the SAPP have focused on the level of trade or infrastructure constraints that bilateral contracts impose on potential market transactions (Bowen et al., 1999; Wright, 2014). There has been no study of the impact of the SAPP's market design rules for integrating bilateral and market trading on either market efficiency or security of supply.

This study is thus designed to address four key questions:

- Under existing rules, what impacts do bilateral contracts have on the efficient functioning of the regional market?

- Under existing rules, what impacts do bilateral contracts have on security of supply for contract holders?
- What are alternative methods to integrate bilateral and market trading in order to minimise market distortions while ensuring the same level of security of supply for contract holders?
- How can such methods be integrated in practice into the existing market design?

3 Materials and methods

3.1 Model description

To measure the impact of bilateral contracts on the SAPP system, we developed a security-constrained economic dispatch model to simulate generation and power trading in the regional market. The model minimises the cost of electricity generation using linear programming. The approach is deterministic, covering the hourly operation over a 1-week period, and represents the 2015 SAPP system. Under this assumption, non-operating members (Tanzania, Angola, and Malawi) are not included in the model as these countries are not physically connected to the regional grid.

The regional network is represented using a simplified transportation model where each country is represented as a single node. Although this approach simplifies the complexity of physical network to only capture the transfer capacity limits between contiguous countries, it is able to capture the relevant higher-level impacts that bilateral contracts and operating rules may have on trade flows that are of interest for this study.

The complete model formulation can be found in Appendix A.

3.2 Input data

Tables 2 and 3 contain the installed capacity and operating parameters for each country and generator type. To reduce the dimensionality of the problem, individual power plants are grouped by technology. The group 'hydro' includes both reservoir and run-of-river hydropower plants. Although this incorrectly represents run-of-river plants as dispatchable, these plants account for <2% of the total hydropower capacity. The parameter *Availability Factor* is used to reduce the maximum capacity of each plant to reflect power consumed for the plant's own use and periods when the plants are unavailable because of planned or unplanned outages. For wind and solar technologies, resource availability for each country is based on monthly capacity factors calculated for each country from climate data, wind and solar simulation models, and geospatial data (Fant, 2016, in press).

Table 2: Installed capacity for SAPP countries by technology (in megawatts)

Country	Biomass	Coal	Distillate	Gas	Hydro	Nuclear	Solar	Wind	Total
Botswana		502	70	90					662
DRC				14.5	2353				2367.5
Lesotho					72				72
Mozambique			64	232	2157				2453
Namibia		120	46.5		330				496.5
South Africa	18	36 437	1833	2791	2239	1888	1233	1160	47 599
Swaziland					60.5				60.5
Zambia			50	60	2149				2259
Zimbabwe		1384			750				2134
Total	18	38 443	2063.5	3187.5	10 109.5	1888	1233	1160	58 103.5

Source: SAPP (2015) and S&P Global Platts (2010).

Table 3: Techno-economic parameters for generation technologies

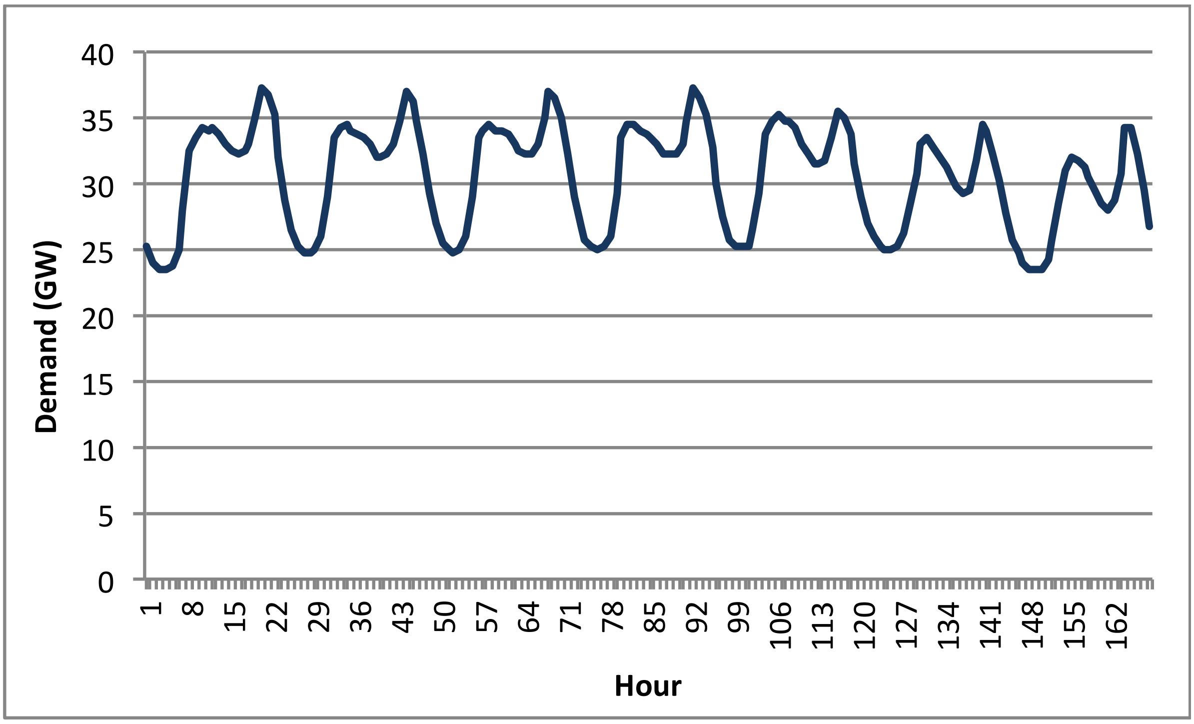
Technology	Country	Heat rate (MMBTU/MWh)	Variable cost (US$/MWh)	Availability factor (%)	Fuel cost (US$/MMBTU)
Biomass	South Africa	13.3	5.4	50	1.6
Coal	Botswana	12.2	3.4	65	0.5
	Namibia	11.4	1.3	88	0.4
	South Africa	8.3	0.5	82	0.4
	Zimbabwe	11.4	1.3	88	0.7
Distillate	Botswana	13.3	17	80	17.2
	Namibia	12.3	11	88	17.8
	Mozambique	11.8	3	80	12.8
	South Africa	13.1	16.1	73	16.7
	Zambia	11.5	3	80	12.8
Gas	Botswana	11.4	19.9	85	9
	DRC	11.4	19.9	85	9
	Mozambique	11.4	19.9	85	9
	South Africa	27.1	15.6	79	10.6
	Zambia	11.4	19.9	85	11.6
Hydro	DRC		1.51	70	
	Lesotho		1.51	65	
	Mozambique		1.51	84	
	Namibia		1.51	60	
	South Africa		1.51	70	
	Swaziland		1.51	37	
	Zambia		1.51	65	
	Zimbabwe		1.51	61	
Nuclear	South Africa	10.1	0.71	81	
Solar	South Africa				
Wind	South Africa				

Source: Black & Veatch (2012) and Miketa & Merven (2013).

In addition to these generators, an additional dummy generator, energy non-served (ENS), was added to account for hours when supply is not sufficient to meet demand. ENS is assumed to have 100% availability and a variable cost of US$800/MWh. The high variable cost serves as a penalty for not meeting demand.

Hourly demand values for each SAPP country are not publicly available. Therefore, hourly demand is based on a representative week in South Africa at the end of June 2015 (Eskom, 2014) (Figure 3). This corresponds to the region's annual peak demand. For other countries, hourly load curves were modelled after those of South Africa and scaled based on their equivalent peak demand. Although imperfect, this simplification is not unrealistic because SAPP countries are reported to have almost no load diversity with demand peaking at almost the same time in each country. In addition, South Africa accounts for nearly 80% of total demand in the region and its demand profile will be the key driver for generation and trade patterns. A shortcoming of this approach is that it does not account for potential differences from different demand sectors (e.g. residential, industrial, commercial) in each country that could change the shape of the demand curve when aggregated at the regional level.

Figure 3: Hourly load curve for sample week in South Africa



Notes: Demand in all other countries is assumed to follow a similar pattern.

Source: Authors' illustration based on Eskom (2014) and SAPP (2015).

The transmission network includes all existing interconnections between member countries and does not include intra-national networks. Table 4 shows the transfer capacities between member countries. All transmission lines are assumed to have energy losses of 2.5%.

Table 4: Transfer capacity in SAPP network

Country	Country	Transfer capacity (MW)
Botswana	Zimbabwe	850
Mozambique	Swaziland	1450
	Zimbabwe	500
South Africa	Botswana	800
	Lesotho	230
	Mozambique	3850
	Namibia	750
	Swaziland	1450
	Zimbabwe	70
Zambia	DRC	260
	Namibia	400
	Zimbabwe	1400

Source: SAPP (2014b).

Data on bilateral contracts are based on the most recent published information available from the SAPP (Table 5). This information only included the co-signers and contracted capacity. Details regarding how the contracts must be fulfilled are proprietary and not publicly available. For this study, all contracts are assumed to be flat (i.e. the co-signers are responsible for delivering/buying the same capacity every hour).

Table 5: Bilateral contracts between SAPP members

Country	Country	Bilateral contract (MW)
EdM (Mozambique)	SEC (Swaziland)	40
	NamPower (Namibia)	40
	BPC (Botswana)	45
HCB (Mozambique)	Eskom (South Africa)	1370
	ZESA (Zimbabwe)	250
ZESA (Zimbabwe)	NamPower (Namibia)	80
SNEL (DRC)	Eskom (South Africa)	150
	ZESA (Zimbabwe)	100
Eskom (South Africa)	LEC (Lesotho)	100
	EdM (Mozambique)	120
	NamPower (Namibia)	200
	BPC (Botswana)	210
	SEC (Swaziland)	96
	MOZAL (Mozambique)	950

Source: Chikova (2009).

3.3 Case studies

The model was run with multiple cases designed to represent different market rules for integrating bilateral and market trades. Bilateral contracts can be designed to include physical or financial obligations. Physical obligations require the physical use of designated infrastructure (e.g. transmission line, power plant) to fulfil the contract. This format puts the greatest constraint on the operation of the system but also guarantees that power will be delivered as promised. Financial contracts (FCs), by contrast, only require exchanges of money and do not influence the physical operation of the system. To compare different methods for treating bilateral contracts, we tested a range of contract designs including physical and financial components (Table 6).

Table 6: Case studies developed for different contract formats

Case Study	Description
Base case	Assume there are no bilateral contracts. Generation and trade are computed in the short term based purely on least-cost principles. This provides a baseline of maximum efficiency for comparison.
Physical transmission (PT)	Contract holders retain PT rights that can only be used to meet their contract obligations but energy obligations are financial. This reflects the current SAPP policy.
Physical contracts (PCs)	Contract holders retain PT rights and have physical obligations to meet energy contracts with their own power plants. This reflects what is generally practised in the SAPP.
Financial contracts (FCs)	Both transmission and generation components are purely financial. This format is commonly viewed as the most efficient way to implement bilateral contracts.
Scarcity	Each of the above scenarios was tested under normal and scarcity conditions. For South Africa and Mozambique, scarcity is simulated as 20% of the country's generating capacity being unavailable. All other countries that have a limited number of power plants or rely heavily on one or two large hydro plants. For these countries scarcity is simulated as 50% of the country's generating capacity being unavailable.

Source: Authors' compilation.

The SAPP's market rules mandate that bilateral contract holders must obtain physical transmission (PT) rights for their contracts but can transfer their energy obligations to third parties. In other words, the energy obligation is financial and they are not obligated to meet these contracts with their own power plants if there is a more economic alternative. This rule allows generators to seek the least-cost supply to meet their contractual obligations but it does not encourage efficient use of the transmission network because their reserved transmission capacity will go unused. In practice, SAPP members are reported to treat these contracts as physical energy obligations as well and self-schedule their own generators to meet all contract obligations even if there are lower-cost suppliers available in the market (Roets & Chauke, 2015).

FCs are widely considered to be the most efficient format because they incentivise participants to sign contracts consistent with the efficient operation of the system but do not impact system operations. Participants earn money through differences in nodal prices between the points of injection and withdrawal described in the contract. Those that sign FCs in the 'right' direction (i.e. the same direction that trade would flow under purely least-cost objectives) can earn revenues because the difference in nodal prices will be positive as power flows from low- to high-cost areas. On the other hand, those who sign contracts in the 'wrong' direction could lose money. FCs are widely used across systems in the United States.

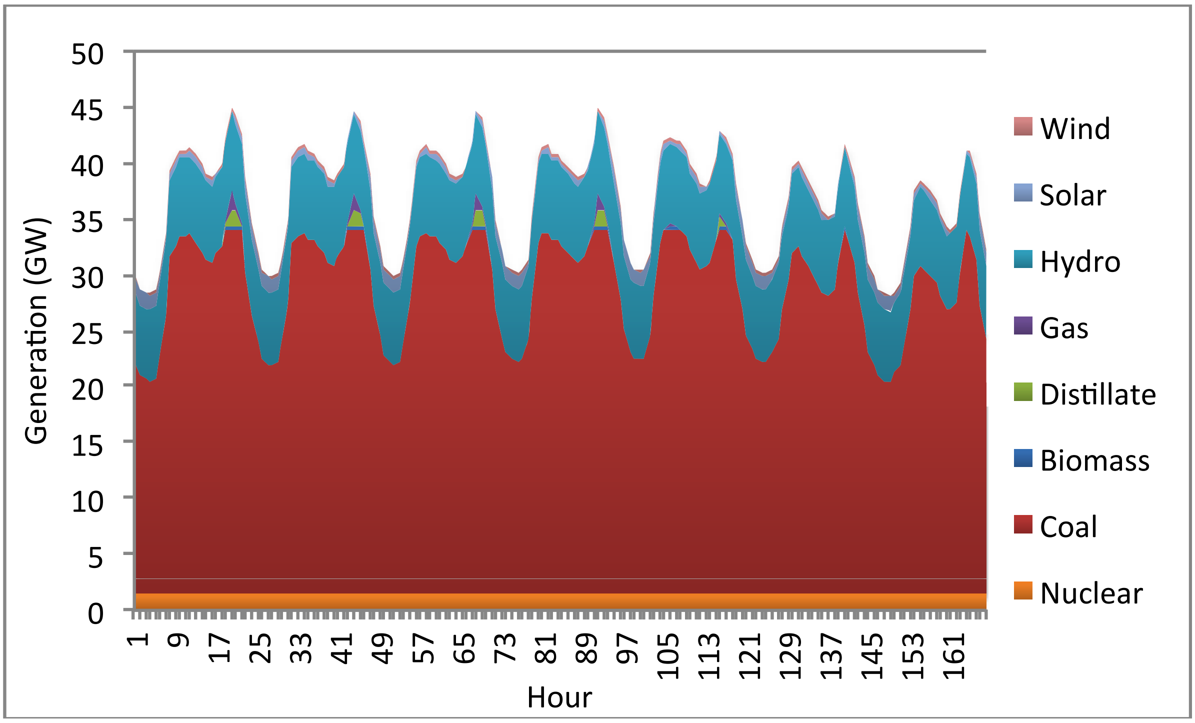
4 Results

4.1 System operations

Figure 4 shows the least-cost generation profile over the week for the 'base case' with no bilateral contracts. Generation is dominated by coal in South Africa, accounting for 75% of total output. Hydropower from South Africa, DRC, Mozambique, Zimbabwe, and Zambia is the second largest contributor. The largest producer is South Africa with 85% of total generation.

In the base case, there are no bilateral contracts and over 20% of electricity generated is traded in the regional network. A simple way to see whether bilateral contracts could influence efficient operation of the network is to compare the least-cost trades achieved in the base case with the power exchanges agreed through bilateral contracts (Figure 5). The size of the orange arrow indicates the total volume of energy traded in the base case. The red arrows indicate the direction of trade for bilateral contracts. Notably, in two cases (circled), bilateral contract exchanges are in the opposite direction as the least-cost trading solution. These are potential cases where physical network and trading obligations from bilateral contracts may lead to inefficiencies in the PT and physical contract (PC) scenarios and economic losses in the FC scenario.

Figure 4: Hourly generation profile for the base case



Source: Authors' illustration.

4.1.1 PT

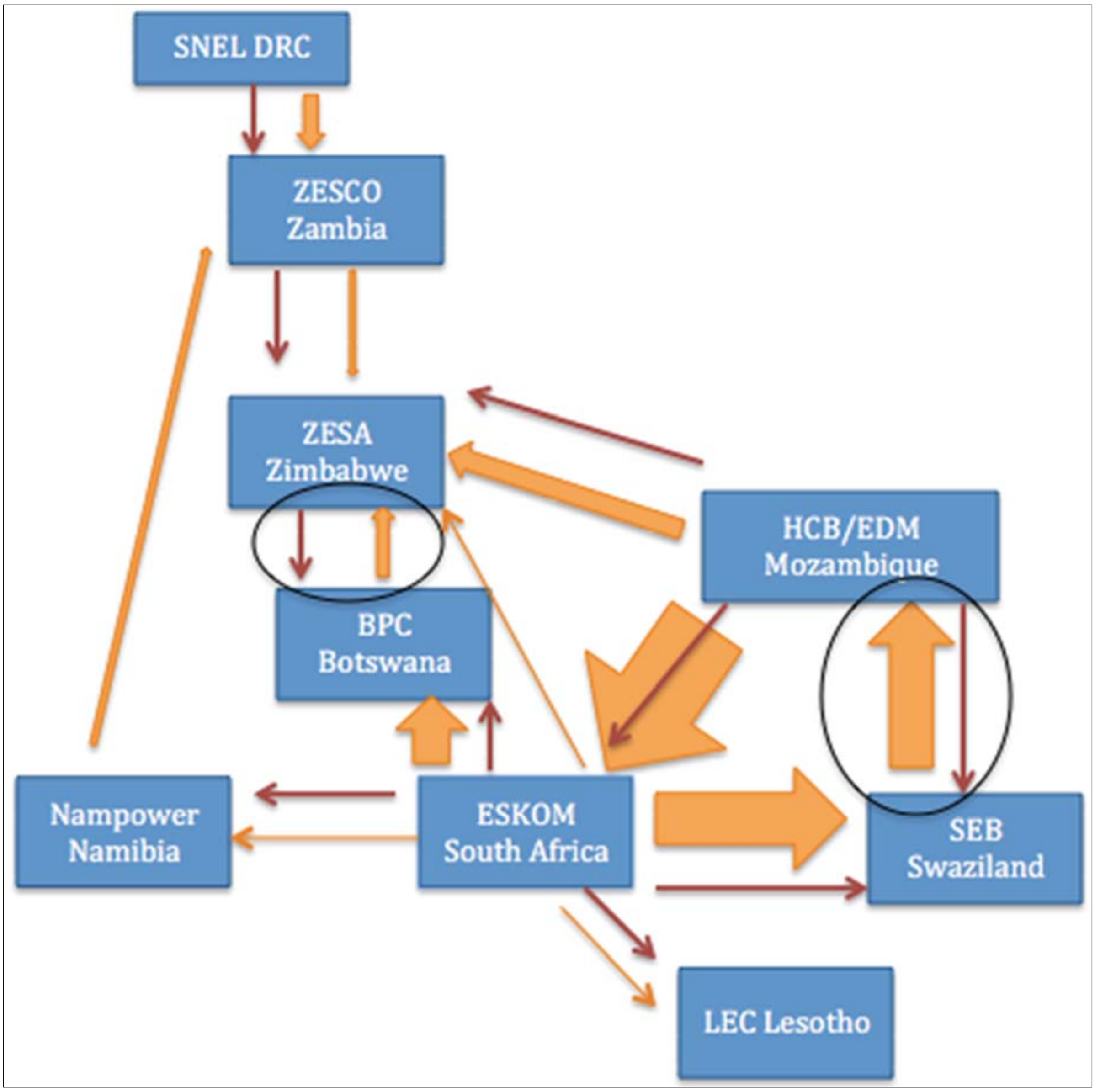
In the PT scenario, total cross-border trade falls by 2%. The reduction in trade is due to the fact that some portion of transmission capacity must be reserved for bilateral trades but, if these trades are not economic because they would require dispatching higher cost generators, this transmission capacity goes unused. Across individual lines, net trade flows changed by an average of 13% with some lines being used more whereas others are used less owing to contract constraints.

PT rights also cause small changes in generation output from different countries. Zimbabwe's imports from Mozambique decrease because Mozambique is exporting more power to South Africa. As a result, total production in South Africa decreases and Zimbabwe experiences a small number of hours with ENS. These changes are small, accounting for <1% of total generation.

4.1.2 PCs

The impact on system operations in the PC scenario is larger because this method constrains the use of the transmission network and introduces mandatory imports and exports for contract holders. Total cross-border trade falls by 50% compared to the base case and, for the two connections circled in Figure 5, trade flows are constrained to go in the opposite direction. Trade across lines that are not contracted (i.e. Namibia–Zambia and South Africa–Zimbabwe) increase whereas trade across lines that are contracted in the apparent wrong direction (i.e. Mozambique–Swaziland) decrease. The average change in trade flows across individual lines is 32%, indicating that PCs require significant changes in the efficient operation of the system.

Figure 5: Comparison of optimal trade flows in the base case with existing bilateral contracts



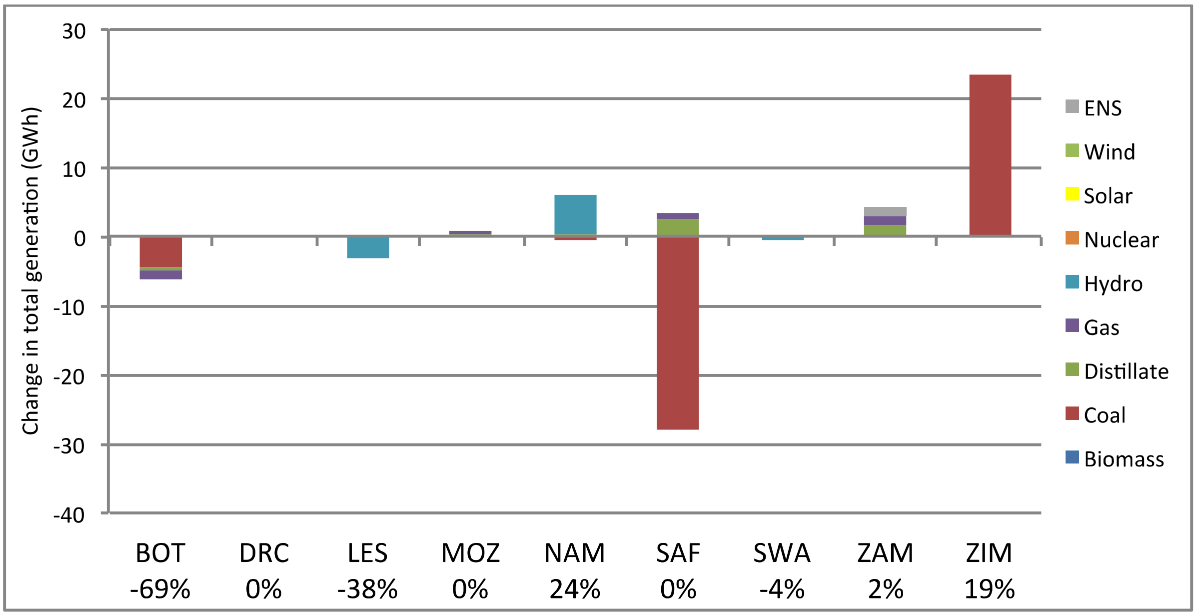
Source: Authors' illustration.

PCs also impose larger changes in generation. Some countries, such as South Africa, have fewer export opportunities because their neighbours now import power from other adjacent countries with which they have bilateral contracts. As a result, total generation in South Africa decreases. Others, such as Zimbabwe, must increase generation in order to meet contractual obligations. Figure 6 shows the change in total production in the PC scenario compared with the base case. The numbers below the country indicate the change in output for each country. As the figure shows, the change can be significant for some countries.

4.1.3 FCs

As purely financial instruments, FCs have no impact on system operations. Trade flows and economic dispatch remain the same as the base case.

Figure 6: Impact of physical contracts (PCs) on total production from each country



Source: Authors' illustration.

4.2 System costs

As expected, the base case has the lowest total generation costs. The absence of bilateral contracts allows generation and trade outcomes to be based purely on least-cost criteria. The PT scenario has very limited impact on total costs (<1%) compared with the base case. Despite reductions in trade, only small changes in generation were needed. The more restrictive PC scenario increased total costs by 13% compared with the base case. In this scenario, countries had fewer options to shift generation among countries with lower costs owing to additional constraints on network usage and generation output imposed by bilateral contracts. For example, coal plants in Zimbabwe were forced to produce in order to meet Zimbabwe's export obligations, displacing output from lower-cost coal plants in South Africa and Botswana.

The largest source of cost increases for both the PT and PC scenarios is penalties from ENS. In both scenarios, ENS occurred in some countries as a result of additional constraints on the use of transmission and generation assets. ENS, which carries a penalty of US$800/MWh, accounts for 63% of the cost increase in the PT scenario and 34% of the increase in the PC scenario.

In the FC scenario, system costs remain unchanged because these arrangements do not influence system operations but the contracts do have economic implications for their holders.

The revenue from a financial transmission contract is equal to the size of the contract (megawatts) times the difference in nodal prices between the injection and withdrawal points. From inspecting Figure 3, we expect that contracts in the opposite direction of the least-cost power flows (i.e. from Mozambique to Swaziland and Zimbabwe to Botswana) would result in economic losses. This is confirmed by calculating expected revenues from differences in nodal prices in the base case.

4.3 Security of supply

The four market designs were run under nine 'scarcity' scenarios to simulate supply shortfalls in each individual country. Security of supply was measured as the total ENS over the model period. We did not consider national energy concerns such as reliance on imports, or other factors such as the time of day or duration of ENS occurrences.

To analyse how holding a bilateral contract impacts a country's security of supply, we divided SAPP countries into 'importers', 'exporters', and 'neutral' based on the sum of all contracts each country has signed. For example, South Africa has both importing and exporting contracts but is classified as an exporter because it is contracted to export more than it imports. Exporters are DRC, South Africa, and Mozambique. Zambia is the only neutral country. All others are importers.

For both the PT and PC scenarios, imposing bilateral contracts during scarcity conditions increased the total amount of ENS in the region because of increased restrictions on trade. Table 7 shows the impact of including different bilateral contract designs on ENS averaged over all scarcity scenarios. Increased ENS fell almost exclusively on countries with bilateral contracts to export power. Countries with net import contracts experienced fewer hours of ENS compared with the base case.

Table 7: Impact of bilateral contract designs on energy non-served (ENS) experienced by different types of contract holders (GWh)

	Total ENS	Importers	Exporters	Neutral
Base case	27	15	12	0
PT	31	13	17	1
PC	53	2	40	11

Source: Authors' illustration.

The results of the scarcity tests indicate that bilateral contracts with a physical component (transmission rights and/or generation obligations) can be effective tools at ensuring electricity supplies for power purchasers during scarcity. The greatest protection for importing consumers came from the PC scenario.

5 Proposed method: Implicit auction with security of supply guarantees

The modelling exercise demonstrates that the current practice of treating bilateral contracts as physical obligations for the use of transmission and/or generation assets results in distortions in the least-cost dispatch and trade patterns, increased ENS, and increased costs for the region as a whole. From an economic efficiency perspective, the most efficient contract design is an FC, which carries no physical obligation and, therefore, does not negatively impact system operations.

On the other hand, bilateral contracts with physical components are effective tools to ensure security of supply for importers during scarcity conditions. This is an important benefit in the SAPP, where member countries have suffered from generation shortages since 2007. As purely financial instruments, FCs do not protect importers from load shedding during scarcity. In addition, bilateral contracts are generally viewed to be necessary among project developers and financing institutions for investments in new power plants and energy-intensive industries. As a result, utilities and major consumers are likely to continue relying on them as a key risk mitigation tool.

The regional market needs a new method for integrating bilateral and market trades that combines the desirable features of physical and FCs. When there is no scarcity the contracts would not interfere with the efficient functioning of the market similar to a FC. When there is a scarcity problem, the contracts would offer consumers and investors the same level of risk reduction provided by firm bilateral contracts. Importantly, this method must be compatible with the current market structure and institutional capacities in the SAPP so that it can be feasibly implemented.

5.1 Description of proposed rule

We propose replacing the existing methods for treating bilateral contracts with an 'implicit auction' with security of supply guarantees. Implicit auctions allocate energy and transmission capacity together through a single market clearing process that jointly considers generation and transmission constraints. As the grid is implicitly taken into account during the dispatch algorithm, implicit auctions maximise the efficient use of the transmission network (Gilbert et al., 2002).

Under this method, parties can continue to sign long-term contracts for any desired capacity with a privately negotiated strike price, subject to transmission constraints but, instead of PCs, these contracts will be partly modelled after a contract for differences (CfD), a purely financial instrument with no physical energy or transmission rights. In addition to the CfD, the system operator will consider the contracts only if there is a supply problem. Unlike a traditional CfD that does not account for emergency conditions when consumers are unable to procure their contracted power or generators are constrained to be off owing to transmission failures, additional penalty features will be included to ensure that generators and transmission owners with long-term contracts have an incentive to be available when needed and are responsible for any risk associated with non-compliance.

The outcome of the proposed contract design is:[4]

In normal conditions:

- contract holders are fully hedged to consume/produce the contracted quantity at the contract price; and
- contract holders have incentives to respond to actual market prices.

In scarcity conditions:

- contract holders are guaranteed the same level of security of supply/income or equivalent compensation as they would receive if contracts were physical; and
- penalties are assigned to the party responsible for the problem.

[4] See Appendix B for a further discussion of contract for differences and mathematical proof of these outcomes.

5.1.1 Implementation under normal conditions

Implicit auctions are difficult to implement in regional markets where multiple system operators are responsible for energy dispatch and network allocation (Pérez-Arriaga, 2013). This is particularly true in international systems that must coordinate system operations across multiple national markets. For large regional markets, a centralised implicit auction may not be feasible owing to the size of the computational problem. In these cases, the problem must be solved in multiple levels.

The SAPP has two characteristics that may relieve some of the difficulties of implementing an implicit auction scheme. First, system operations for all member countries are already clustered among three control area system operators and the SAPP is the only competitive market in the region. Therefore, the process to centralise system operations is much simpler than if each country had its own national market and system operator. Second, the regional transmission network only has a limited number of high voltage lines. This allows the SAPP MO to capture the entire regional network with a single model that is computationally tractable.

To implement a centralised implicit auction, several changes will be needed to the current market rules in the SAPP. For market participants, all generators and consumers must submit bids to the SAPP MO. Consistent with rational market behaviour, these bids should be based on their marginal costs, ignoring the existence of any bilateral contracts. Generators with bilateral contracts will continue to obtain transmission rights for their contracts to ensure their trades are technically feasible but these rights are purely financial rather than physical. Contract holders must continue to notify the SAPP MO of all bilateral contracts but they will no longer be able to self-schedule through their local control area system operator.

Under this scheme, the SAPP MO will be solely responsible for allocating transmission capacity and scheduling generators. Rather than running the competitive market on top of self-scheduled bilateral trades communicated through control area operators, the SAPP MO will collect all bids and run a single security-constrained economic dispatch algorithm. Although the SAPP will continue to collect information on all bilateral contracts, these contracts will not be considered in the system dispatch unless there is a supply problem. Control area system operators can continue to monitor intra-day balancing, but they will lose authority to schedule day-ahead transactions.

5.1.2 Implementation under scarcity conditions

The SAPP considered implementing CfDs to increase liquidity in the DAM as early as 2011 but did not pursue it because of fears that 'there is more exposure for buyers of power when bilateral contracts are cleared through the DAM' (SAPP, 2011:22). Given these fears and the current supply constraints in the region, a 'security of supply guarantee' will be included in the proposed method for market scheduling. This guarantee mandates that, when there is scarcity, members with supply contracts must have the same level of supply (no increase in ENS) as the case where contracts are physical. This may require changes to the least-cost dispatch schedule but does not require that contracts be physically imposed.

The guarantee should be implemented based on a predictable and transparent process by an independent entity. As the SAPP MO is already responsible for organising the dispatch schedule and is not affiliated with any national utilities or governments, this entity should be responsible for any necessary schedule adjustments during scarcity events. The following steps outline the proposed method for the SAPP MO to handle contingency events:

- Run security-constrained economic dispatch to determine the least-cost scheduling of generators.
- If there is ENS, rerun the dispatch model assuming all bilateral contracts are PCs. This will provide a baseline level of ENS for participants with bilateral contracts if contractual obligations are honoured.
- If consumers with supply contracts are not receiving the same level of supply as the baseline value (i.e. every hour their ENS must not exceed what is achieved in the PC scenario), rerun the dispatch model with a constraint that ENS for these consumers must not exceed their baseline values.
- In extreme cases, such as multiple failures, it may not be possible for all consumers with supply contracts to receive their guaranteed level of supply and the scheduling problem will not have a feasible solution. In this case, the SAPP MO must prioritise which contracts will be imposed. For simplicity and continuity, prioritisation should follow the existing scheme already in place in the SAPP where firm contracts are prioritised over non-firm contracts and older contracts are prioritised over newer ones. Following this, the SAPP MO would enforce supply obligations as needed in the dispatch schedule (starting with older, firm contracts) until the economic dispatch problem is feasible. Consumers with contracts that do not receive their guaranteed level of supply will receive a penalty payment from the party responsible for the problem as agreed in the contract.

5.2 Model results with proposed method

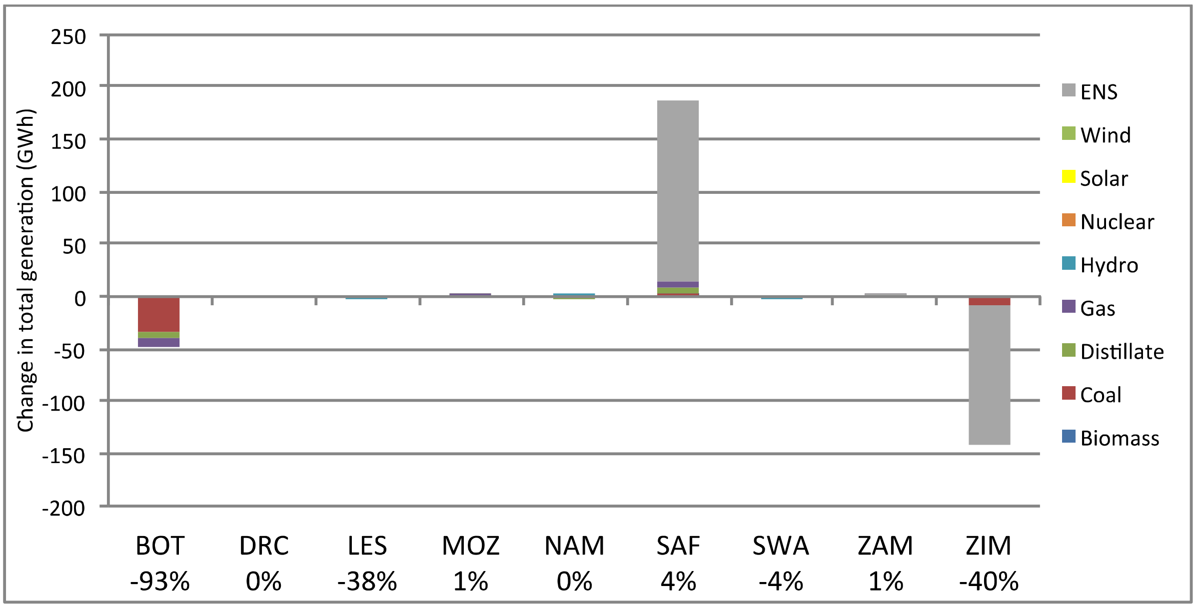
The SAPP model was rerun assuming bilateral and market exchanges were scheduled following the implicit auction method. The mathematical equations used to formulate this scenario are described in Appendix A. Under normal conditions, the proposed method has no impact on generation, trade, network usage, or costs compared with the base case. This means the implicit auction method avoids all the market distortions modelled under the previous scenarios when there is no scarcity. The following sections compare how the implicit auction method performs when there is scarcity.

5.2.1 System operations

When there is scarcity, the implicit auction design has a significantly smaller impact on trade flows and production than the PC scenario. Recall, PCs decrease average regional trade by an average of 50% (2% for PT rights) during scarcity. By contrast, on average, implicit auctions decrease trade flows by 10% compared with the base case. The impact is higher than the PT scenario because of larger changes needed for all lines connected to Zimbabwe, a net importer, in order to ensure security of supply for this country. The average change across all lines is only 8% compared with 13% and 32% in the PT and PC scenarios, respectively.

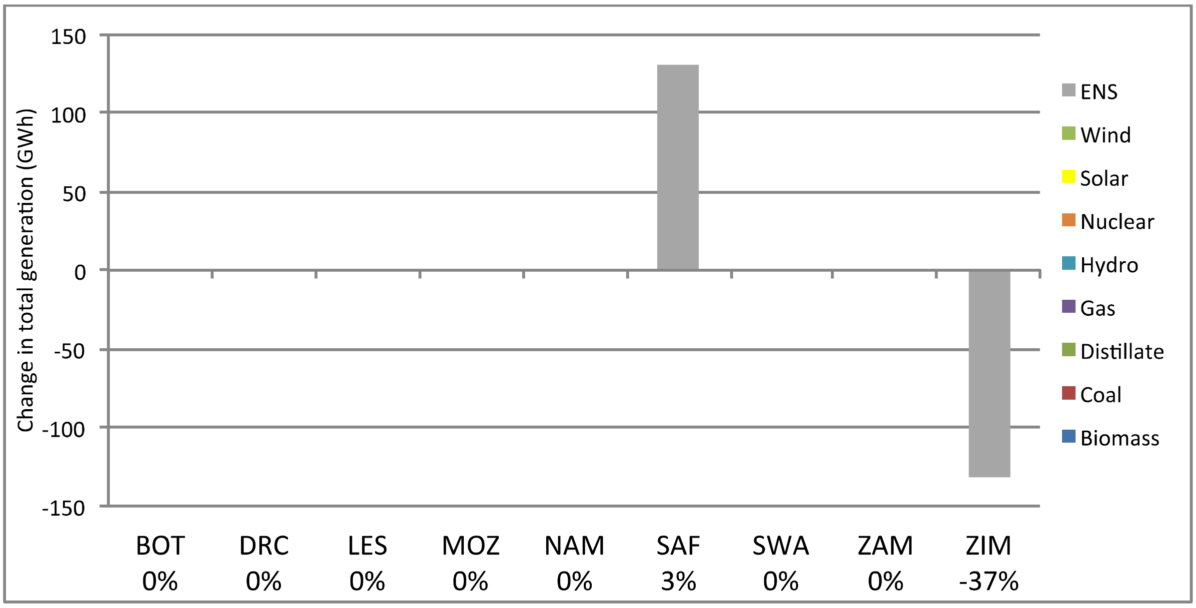
Implicit auctions also require less deviation in generation than the PC scenario. An example of changes in generation compared with the base case when there is scarcity in South Africa is shown using PCs and implicit auctions in Figures 7 and 8, respectively. In both cases, the total ENS in countries with import contracts (i.e. Zimbabwe) is reduced because the contracts guarantee their supply. However, implicit auctions offer the same level of protection with less deviation from the least-cost solution in terms of both the number of countries forced to change their generation output and the magnitude of changes required.

Figure 7: Change in generation output during scarcity in South Africa under the PC scenario



Source: Authors' illustration.

Figure 8: Change in generation output during scarcity in South Africa under the implicit auction scenario



Source: Authors' illustration.

5.2.2 System costs

During scarcity, implicit auctions had significantly less impact on system costs than the PT and PC scenarios. The average cost increase over all scarcity scenarios was <0.5%. By contrast, PT rights increased system costs by <0.5% in normal conditions and 8% during scarcity whereas PCs increased costs by 13% in normal conditions and 51% during scarcity.

It is important to note that this result holds for the current configuration of bilateral contracts, network capacity, and input parameters tested. In other systems with larger variations in fuel costs, generation technologies, cost of ENS, contracts, or network topology, implicit auctions could increase the total system costs compared with a base case during scarcity by a larger amount if the system operator is forced to redirect power flows or constrain off lower-cost generators to guarantee contract holders the same level of supply. However, these increases will not exceed those experienced by PT rights or PCs because implicit auctions have fewer constraints on the use of transmission and generation infrastructure to meet demand at lowest cost.

5.2.3 Security of supply

Table 8 compares the total ENS averaged over all scarcity scenarios for importers, exporters, neutral countries, and the region as a whole. The results show that both importing countries and the region as a whole are better off (less ENS) with implicit auctions compared with the PT and PC scenarios.

Table 8: Impact of implicit auctions compared with previous contract designs on ENS experienced by different types of contract holders

	Total ENS	Importers	Exporters	Neutral
Base case	27	15	12	0
PT	31	13	17	1
PC	53	2	40	11
IA	27	0	27	0

Source: Authors' illustration.

In Table 8, importing countries experience less ENS with implicit auctions than with PCs. This is due to input assumptions about supply and demand parameters in each country, not the implicit auction method itself. The implicit auction method only requires that ENS in importing countries should not exceed what is achieved with PCs (2 GWh in this case). If, for example, the cost of ENS were very high in exporting countries, the cost-minimising solution would be to minimise ENS in these countries. In this case, total ENS in importing countries would be 2 GWh (the maximum allowable) and any remaining necessary load shedding would be in exporting or neutral countries.

6 Discussion and conclusions

High levels of bilateral trade in southern Africa have limited the participation in the region's competitive short-term markets. At the same time, governments and market participants are unlikely to forego their preference for long-term contracts because of concerns about security of supply and risk mitigation. In this paper, we demonstrate that the current method for integrating bilateral and market trading introduces inefficiencies in the use of generation and transmission infrastructure, reduces total trade, and increases system costs. At the same time, these contracts – assuming they are respected – play a key role in increasing security of supply during emergencies.

To capture the security of supply benefits of bilateral contracts while minimising market distortions, we propose a new method of implicit auctions with security of supply guarantees. The implicit auction scheme will require changes in how generators, consumers, and system operators interact with the SAPP MO, but the SAPP is well positioned to implement these changes. Modelling simulations of the method show that during normal conditions, it has no impact on the efficient functioning of the market. During scarcity conditions, the implicit auction scheme offers the same level of protection for countries with import contracts, but with less impact on generation, trade, and costs compared with existing methods. These results are indicative of the types of impact that the proposed method may have. Further work is needed to refine the scarcity scenarios used for testing, represent the characteristics of existing bilateral contracts, and describe the demand patterns in each country.

Resolving the conflict between security of supply and competition efficiency is not just a critical challenge for the SAPP. Southern Africa also serves as an example for other regional power pools currently being developed, including the West African, East African, and Central African Power Pools. These organisations, still in the process of establishing enabling legislation and regulatory agreements, contain similar characteristics to those found in the SAPP, including insufficient generation and transmission capacity, difficulty mobilising financing, limited experience with market trading and a preference for long-term bilateral agreements. Delegations from other regional pools are already visiting the SAPP to familiarise themselves with its operations and management. Lessons derived from the SAPP to address pressing challenges could, therefore, directly inform the design of regional policies, markets, and regulations for other power pools across Sub-Saharan Africa.

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Appendix A: Model formulation

A unit commitment model of the SAPP system is used to obtain the security-constrained economic dispatch schedule and trade flows over the simulated week. The notations for the model formulation are presented in Tables A1–A3. As a matter of nomenclature, all input parameters are designated with the letter *p* before the name and decision variables with the letter *v*.

Table A1: Indices

Index	Definition
p	Period
c	Country
g	Generation technology
$Lines_{c,c}$	Interconnections between countries
$Trade$	Types of power trade (bilateral, market)

Source: Authors' compilation.

Table A2: Input parameters

Parameter	Definition	Unit
$pDemand_{p,c,trade}$	Demand	Megawatt
$pBilatContract_{c,c}$	Bilateral contracts	Megawatt
$pCapacity_{c,g}$	Generation capacity	Megawatt
$pAvailabilityFactor_{c,g}$	Availability factor	Percentage
$pHeatRate_{c,g}$	Heat rate	1 million British thermal units per megawatt-hour
$pRenewCF_{p,g,c}$	Capacity factor for wind and solar	Percentage
$pVariableCost_{c,g}$	Variable cost	US dollar per megawatt-hour
$pFuelCost_{c,g}$	Fuel cost	US dollar per 1 million British thermal units
$pTx_{c,c}$	Transfer capacity	Megawatt
$pLosses$	Line losses	Percentage

Source: Authors' compilation.

Table A3: Decision variables

Variable	Definition	Unit
$vConCapacity_{c,p,g}$	Connected capacity (synchronised to the grid)	Megawatt
$vGeneration_{c,p,g,trade}$	Generation	Megawatt
$vGxCost_{c,p}$	Generation cost	US dollar
$vResBilDemand_{p,c}$	Bilateral demand that must be met by the market	Megawatt
$vTrade_{c,c,p,trade}$	Electricity trade	Megawatt

Source: Authors' compilation.

The index *trade* is used to distinguish between market and bilateral transactions. For countries with bilateral contracts to purchase power, total demand is composed of bilateral demand (based on the quantity of contracts signed) and market demand. Similarly, generation and trade are divided between bilateral and market. For countries with no contracts, the bilateral component for demand, generation, and trade is always zero.

A1 Objective function

The objective function is minimisation of all generation costs over the simulated week. Generation costs consist of: (i) running costs for units synchronised to the regional grid but not necessarily producing power, (ii) fuel costs, and (iii) variable costs.

$$Min \sum_{c,p,g} vConCapacity_{c,p,g} \times pVariableCost_{c,g}$$
$$+\sum_{trade} vGeneration_{c,p,g,trade} \times pHeatRate_{c,g} \times pFuelCost_{c,g}\,. \tag{A1}$$
$$+vGeneration_{c,p,g,trade} \times pVariableCost_{c,g}$$

A2 Constraints

The dispatch schedule is subject to constraints on the available capacity of each technology, transfer capacity between countries, and requirements that supply must meet demand in every period.

A2.1 Available capacity

The total capacity available to be dispatched is less than the total installed capacity because power plants use some portion of their power internally and must go offline occasionally for maintenance. For wind and solar plants, output also depends on the resource availability, which may vary throughout the day. The parameters *pAvailabilityFactor* and *pRenewCF* take on values between 0 and 1 to account for the fraction of installed capacity available in each period. For example, solar plants may have a *pRenewCF* value of 0.8 during the day, indicating that a 100-W plant could generate up to 80 W during this time, and a value of 0 at night when there is no sunlight. For all non-renewable plants, the value of *pRenewCF* is set to 1.

$$vConCapacity_{c,p,g} \le pCapacity_{c,g} \times pAvailabilityFactor_{c,g} \times pRenewCF_{p,g,c}\,. \tag{A2}$$

A plant must be running and synchronised to the grid to produce power. Therefore, total generation in any hour cannot exceed the connected capacity during that time.

$$\sum_{trade} vGeneration_{c,p,g,trade} \le vConCapacity_{c,p,g}\,. \tag{A3}$$

A2.2 Transfer limits

Total power trade is limited by the physical transfer capacity between countries. For bilateral trade, the maximum allowable trade is limited by the capacity of the contract, *pBilatContract*. Any remaining transfer capacity not used for bilateral trade can be used for market trading.

$$0 \le vTrade_{c,c,p,Bil} \le pBilatContract_{c,c}, \tag{A4}$$

$$pBilatContract_{c,c} - pTx_{c,c} \le vTrade_{c,c,p,Mkt} \le pTx_{c,c} - pBilatContract_{c,c}. \tag{A5}$$

A2.3 Supply demand balance

The supply demand balance equations are divided into two parts: bilateral and market. Bilateral demand comes from capacity that countries have contracted to receive or provide. Any residual bilateral demand not met by domestic generation or bilateral trade is captured by the variable *vResBilDemand*.

$$vResBilDemand_{p,c} = pDemand_{p,c,Bil} + \sum_{Lines(c,cf)} vTrade_{c,cf,p,Bil} \times pLosses$$
$$- \sum_{Lines(ci,c)} vTrade_{ci,c,p,Bil} \times pLosses - \sum_{g} vProduction_{c,p,g,Bil} \quad . \tag{A6}$$

The market energy balance equation requires that total supply must equal demand in all periods. Supply can take the form of domestic market generation, energy non-served (ENS), and market imports. Demand comes from market demand plus any residual bilateral demand and energy exports.

$$\sum_{g} vGeneration_{c,p,g,Mkt} = pDemand_{p,c,Mkt} + vResBilDemand_{p,c}$$
$$+ \sum_{Lines(c,cf)} vTrade_{c,cf,p,Mkt} \times pLosses \quad . \tag{A7}$$
$$- \sum_{Lines(ci,c)} vTrade_{ci,c,p,Mkt} \times pLosses$$

A3 Contract scenarios

In the base case, all bilateral contracts, *pBilatContract*, are assumed to be '0' and all bilateral demand, trade, and generation values are also '0'. As a result, all transfer capacity is available for market trading (Equation (A5)) and the balance equation for bilateral contracts (Equation (A6)) is not binding.

In the physical transmission (PT) rights scenario, all existing bilateral contracts are included. These contracts must have reserved transmission capacity (Equations (A4) and (A5) are active) but any technology located in any country can meet bilateral demand.

In the physical contract (PC) scenario, all existing bilateral contracts are included and the contract holders must meet these contractual obligations. Two additional constraints are included to impose this rule. The first constraint mandates that domestic generators within countries with export obligations must produce enough to meet these obligations and the second mandates that bilateral trade between countries must match their contracted exchanges.

$$\sum_{g,trade} vGeneration_{c,p,g,trade} \geq \sum_{cf} pBilContract_{c,cf} \; , \tag{A8}$$

$$vTrade_{c,c,p,Bil} = pBilatContract_{c,c}. \tag{A9}$$

The implicit auctions scenario does not explicitly include bilateral contracts. Similar to the base case, all bilateral contracts are assumed to be '0'. Instead, this scenario contains a new constraint on the maximum allowable ENS a country with a purchase contract can experience in any period.

$$\sum_{trade} vGeneration_{c,p,ENS,trade} \leq pBaseENS_{c,p} \, . \tag{A10}$$

The parameter *pBaseENS* is equal to the ENS a country with a purchase contract experienced under the PC scenario. Equations (A8) and (A9) are not active in this scenario.

Appendix B: Contracts for differences (CfDs)

In a CfD, generators and consumers agree to exchange a contracted quantity, q_c, at a fixed price, P_c, known as the contract or strike price. The market clearing price, P_m, serves as the reference price.

The monetary result of the contract is that the consumer pays the generator $q_c(P_c–P_m)$. Note that when the strike price is less than the market price, this value is negative and the generator actually pays the consumer.

B1 Traditional CfD design

With traditional CfDs, if consumers purchase some quantity q from the market at price P_m they will pay the market price for what they consume plus the contract price (Equation (B1)).

$$qP_m + q_c\left(P_c - P_m\right). \tag{B1}$$

Generators earn income from selling some quantity, q, of power to the market and the CfD. Their net revenues include this income minus their generation costs (the quantity produced times their variable cost, VC) (Equation (B2)).

$$qP_m + q_c\left(P_c - P_m\right) - qVC = q_cP_c + \left(q - q_c\right)P_m - qVC. \tag{B2}$$

If consumers buy exactly their contracted quantity, q_c, their resulting costs would be

$$q_cP_m + q_c\left(P_c - P_m\right) = q_cP_c. \tag{B3}$$

Similarly, if generators produce exactly q_c, their net revenue would be

$$qP_m + q_c\left(P_c - P_m\right) - qVC = q_c\left(P_c - VC\right). \tag{B4}$$

In both cases, the final costs/revenues are independent of the market price, P_m. In other words, consumers and producers with CfDs are fully hedged to consume and produce exactly the contracted quantity.

Although contract holders are fully hedged to consume their contracted quantity, ignoring the market price could reduce the efficient functioning of the market. If contract holders held strictly to this rule, generators would be willing to produce even if the market price fell well below their variable cost of generation or consumers would continue buying power even if the market price skyrocketed. Fortunately, CfDs incentivise both parties to respond to market price signals as if the contracts do not exist.

If, for example, the market price rose above P_c, consumers could continue to consume q_c and pay q_cP_c. However, according to Equation (B1), they would be better off reducing their consumption, q, as much as possible and pay $qP_m+q_c(P_c–P_m)$. Note that the second term is negative, meaning the generator would be paying the consumer. On the other hand, if the market price increases above VC, generators have an incentive to produce as much as possible. From Equation (B2), generators could earn an additional P_m-VC for each incremental unit sold over the contracted quantity, q_c.

If the market price falls below P_c and VC, consumers and generators would have the opposite reaction. Buyers could increase their consumption and pay P_m for each additional unit consumed over the contracted quantity. As this price is less than the value the consumer was willing to pay in the contract, consumers are most likely willing to buy more at this price. By contrast, generators would lose $VC-P_m$ for every unit sold. In this case, they are better off shutting down generation and collecting payments from the CfD.

Ignoring the equations or the specific example of electric power systems, these results reflect our intuition about how consumers and producers respond to market prices. When the market price is high, consumers will try to consume less whereas producers want to sell more. When the market price falls, consumers are willing to buy more whereas fewer producers will find it profitable to sell. With CfDs, consumers and producers have an incentive to respond to market prices as if the contracts did not exist.

B2 Proposed contract design during scarcity

Financial contracts, such as CfDs, are sufficient for cases where there is sufficient generation and transmission capacity for consumers to buy and generators to sell q_c. For example, if a generator breaks down, it cannot hedge against market prices by selling power but it can purchase power from the market to cover its contractual obligations. The generator would be fully exposed to the market price, P_m, and its net revenues (from Equation (B2)) are $q_c(P_c-P_m)$. Note that if the market price is higher than the strike price, the generator is exposed to a potential loss. For transmission owners, if the contracted transmission capacity is not available but consumers are still able to receive q_c and generators are still able to sell q_c through alternative network paths, the transmission owner is not subject to any penalty as both the generator and the consumer are fully hedged against market prices.

This framework breaks down when contracted generation or transmission capacity is not available and there are no alternative supplies or network paths to guarantee consumers are able to buy and generators able to sell q_c. This situation is a reality in supply-constrained systems like the SAPP. In these cases, the party responsible for creating the problem must pay some compensation to the contract holders. Under the proposed implicit auction scheme, CfDs must include a per-unit fine for generators, F_G, that are not available when needed and transmission rights contracts must include a per-unit fine for transmission owners, F_T, that are not available when needed. These fines will be applied only if the outage results in the consumer being unable to consume q_c or the generator being unable to sell q_c.

If the generator is not available, they must pay the consumer the penalty cost for every unit not supplied, $F_G(q_c-q)$.

Similarly, if the transmission line is not available, the transmission owner is subject to a fine to both the consumer and the producer for any foregone consumption or revenues that result from the line being down. This amounts to a penalty of $F_T(q_c-q)$ to the consumer and $(q_c-q)(P_c-VC)$ to the generator.

Tables B1 and B2 outline the monetary outcome of the proposed contracts under different scenarios for consumers and producers.

Table B1: Payment by consumers

	Able to consume q_c	Unable to consume q_c
Generator/Transmission available	$qP_m+q_c(P_c–P_m)$	Impossible case
Generator unavailable	$qP_m+q_c(P_c–P_m)$	$qP_m+q_c(P_c–P_m)–F_G(q_c–q)$
Transmission unavailable	$qP_m+q_c(P_c–P_m)$	$qP_m+q_c(P_c–P_m)–F_T(q_c–q)$

Source: Authors' compilation.

Table B2: Revenues for producers

	Able to sell q_c	Unable to sell q_c
Generator/Transmission available	$q_cP_c+(q–q_c)P_m–qVC$	Impossible case
Generator unavailable	$q_c(P_c–P_m)$	$qc(Pc–P_m)–F_G(q_c–q)$
Transmission unavailable	$q_cP_c+(q–q_c)P_m–qVC$	$qP_m+q_c(P_c–P_m)–(q_c–q)(P_c–VC)$

Source: Authors' compilation.