

Grant Support provided by



AFRICA GREENCO FEASIBILITY STUDY



Supported by



Supported by



Supported by



Supported by



Supported by



Presented at



Recommended in the SEforALL
Finance Committee Report



CONTENTS

Letter from the Founder	4
Acknowledgements	6
Executive Summary	9
Structure of this Feasibility Study	21
Glossary	138

1 Alignment with other international and regional initiatives

Alignment with international climate change agenda and other African regional initiatives	22
Alignment with other relevant initiatives and organisations	23

2 Precedent for Power Sector Intermediary – PTC India

Precedent for Power Sector Intermediary – PTC India	24
---	----

3 Contextualising Africa GreenCo

Assessing Offtaker Creditworthiness	30
Implications	32
Credit Enhancement	32
Sustainability of Current Approach	33
Contingent Liabilities and Debt Sustainability	34

4 Target Market

Overview of the power pools within sub-Saharan Africa	37
SAPP Market and AGC SAPP Technical Feasibility Report	38
Transmission Network	39
Identification of a regional project to prove concept	41
Scope of evaluation	42
Proof of Concept Focus Country	46
AGC's expansion opportunities within SAPP	46
SAPP Cross Border Trading	46
AGC Strategy in SAPP	49

5 Financial Viability

Project Analysis	51
Hypothetical Portfolio	51
Operating Model	54
Revenue streams	55
Operating Costs	61
Financing Strategy	64
Development and Establishment Costs	64
Capital Requirement	64
Foreign currency exchange risk	68
Leverage	70
Equity	78
Recommended Financial Structure	89
Financial Performance	91

6 Impact on Power Markets

Benefits for projects and investors	95
Benefits to Utilities	100
Sovereign and Macro-economic Impact	105

9 Conclusion and Way Forward

Next Steps	136
Potential implementation roadmap and timeline	137

7 Contracting Strategy, Risk Allocation and Procurement

AGC Contracting Strategy	110
Project finance basics	111
Overview of typical IPP transaction documents and structure	111
AGC as an intermediary offtaker	113
Key principles influencing the allocation of risks in AGC's PPAs and PSAs	114
Allocation of key risks in AGC's PPAs and PSAs	114
Grid connection and wheeling arrangements	119
Contractual relations with Governments	122
Flow Through Approach v Direct Approach	123
Credit Support Arrangements and AGC's Credit Mitigation Strategies	124
Other Benefits of AGC	126
Procurement Considerations	127

Annexes

Annex 1 - Detailed Allocation of Key Risks in PPAs and PSAs	03
Annex 2 - Africa GreenCo Additionality and Complimentarity Table	42
Annex 3 - Africa GreenCo Technical Feasibility Report	62
Annex 4 - Africa GreenCo Corporate Structure, Regulatory & Governance Options	112
Annex 5 - Application of IMF Debt Sustainability Assessment and Debt Sustainability Framework in Africa	128
Annex 6 - IPP Credit Enhancement Strategies	132
Annex 7 - Utility Creditworthiness Factors and Credit Rating Methodologies	139
Annex 8 - Procurement	147
Annex 9 - Other Precedents for Bulk Power Purchasers	157
Annex 10 - References	159

8 Corporate Structure, Governance and Risk Management

Corporate Structure	129
Governance	130
Risk management	134

LETTER FROM THE FOUNDER

The potential for renewable energy in sub-Saharan Africa is staggering but as noted by Akinwumi Adesina, President of the African Development Bank, during his launch of the New Deal on Energy for Africa, "Africa cannot power its economy with potential".

A principal challenge for host Governments, the African and international development community and others seeking to support the deployment of grid-connected renewable energy in sub-Saharan Africa, is how best to convert this staggering potential into operational projects, which in turn can provide dependable, affordable electricity on the scale required for economic and social development of the region.

Currently, financial support from the international development community is provided largely on a project-by-project basis through a combination of grants, equity investment, debt finance (often on implicitly subsidised terms) and guarantees through which to cover sovereign credit risk. This approach is piecemeal and often lacks co-ordination. It also relies on heavily indebted governments assuming very large contingent liabilities to backstop the obligations of uncreditworthy offtakers, and in many instances it can be seen to crowd-out rather than catalyse private sector finance. This is a sticking plaster, not a real cure. Covering the cracks with financial support and guarantees, whilst further indebting governments, does little to solve the underlying structural and market weaknesses that currently make the provision of finance to the sector so time consuming and expensive.

Recent ICA, World Bank and UN surveys all highlight the lack of offtaker creditworthiness as the key hurdle for private sector investment in Africa. This is reinforced by AfDB's New Deal on Energy for Africa, which calls for a structural shift and moving away from the current project-by-project approach towards an integrated renewable energy strategy and a programmatic approach for renewable energy development and planning.

The innovative solution proposed by Africa GreenCo (AGC) entails the introduction of an independently managed, creditworthy (investment grade), intermediary offtaker and power trader to sit between renewable electricity generation companies on the one hand, and both state owned and private sector offtakers on the other. AGC will operate as a member of the African regional power pools, aggregate offtaker credit risk and diversify both supply and demand side risks on a regional basis. In case of a utility defaulting, AGC will rely on various risk mitigation tools including the right to exercise an option to sell power to other utilities/bulk power purchasers or via the power pool.

This single change will:

- ④ materially reduce risk and cost for project developers and financiers leading to benefits for utilities and power purchasers;
- ④ create a more favourable investment environment for a wider universe of investors;
- ④ reduce the fiscal burden on host Governments by reducing the probability of early termination buyout obligations crystallising;
- ④ allow 'open access' to DFI credit support for private sectors financiers (all project companies contracting with AGC will benefit from AGC as a creditworthy counterparty) and aggregates DFIs willingness to take sovereign credit risk into a single intermediary offtaker;
- ④ more efficiently match electricity supply and demand;
- ④ help optimize deployment of intermittent renewable energy generation facilities on a regional basis;
- ④ increase the liquidity and effectiveness of regional power pools through trading;
- ④ lower transaction costs through standardised documentation and dedicated specialist team;

- ④ provide a mechanism through which to mitigate rigid contractual positions required for bankability and thus increasing the number of bankable projects;
- ④ increase the potential for refinancing – giving confidence to upfront lenders and helping to facilitate long-term capital market / institutional investors engagement; and
- ④ facilitate the move towards local currency denominated PPAs by facilitating an increase in local currency lending to power projects.

With the support of host Governments, and the African and international development community, AGC can provide a structural solution to the underlying problem of renewable energy project bankability. More importantly, AGC will make financing the sector fundamentally more attractive and accessible to private sector sources of capital whilst at the same time reducing pressure on utilities as well as financial liabilities for sovereign governments. Accordingly, AGC expects that it will cause a fundamental step-change in the degree to which DFI support helps mobilise private sector finance.

This Feasibility Study demonstrates the scalability and flexibility of the AGC proposal, and that AGC's solution is applicable to the diverse range of projects and circumstances existing in the region. Once implemented, AGC will offer the best structure for developing large scale regional cross-border power projects such as those supported by NEPAD and the PIDA programme.

AGC aims to learn from, and where possible replicate, the dynamics of more advanced power markets, in particular building on the experience of PTC India (formerly the Power Trading Corporation of India). PTC India was also established in order to act as a credit risk mitigating intermediary offtaker; in the process, it catalysed the entire Indian regional power sector trading market. So whilst the design of AGC has been specifically tailored to the sub-Saharan market, there is strong international precedent showing just how transformational the AGC model can be on the ground.

On behalf of the wider AGC team I thank you in advance for taking the time to read this Feasibility Study. We greatly value your interest and participation in implementing the structural step changes which AGC proposes.

Yours sincerely



Ana Hajduka
(Founder & CEO)

ACKNOWLEDGEMENTS



The Africa GreenCo concept and the current Feasibility Study are presented to the market solely due the support and funding received from The Rockefeller Foundation's Innovative Finance team. The Africa GreenCo team is extremely grateful to The Rockefeller Foundation for their trust, belief and for allowing us to present this ambitious concept to the market. A very special thank you to Saadia Madjesber, Mamadou Biteye and Adam Connaker for guiding us every step of the way and for supporting us in our grant application.



Africa GreenCo is supported by RERA as it responds to Outcome Statement No. 8 of the SADC Ministerial Workshop on Water and Energy held on 20 June 2016 and to the Market and Investment Framework for SADC Power Projects approved by the SADC Ministers responsible for Energy on 21 June 2016, by addressing some of the risks currently undermining developer and investor/lender confidence in the reliability of independent power producers' long-term revenue forecasts. Our special thanks go to Elijah C. Sichone, RERA's Executive Secretary.



SAPP supports Africa GreenCo as its envisaged function is complementary to SAPP's focus of driving the regional agenda of promoting generation and transmission expansion, universal access and increased renewable generation penetration by 2030. Our special thanks go to Alison Chikova and Musara Beta.



The Association of Power Utilities of Africa (APUA) supports Africa GreenCo as a means of securing greater generation capacity at lower cost and supporting African utilities in their transition to creditworthiness. With special thanks to Abel Tella, CEO of APUA.



NEPAD supports Africa GreenCo as a catalyst for regional integration and a facilitator of cross-border power trade and energy policy harmonisation. Our special thanks go to Ibrahim Mayaki, Mosad Elmissiry and Symerre Grey-Johnson.



Convergence supports Africa GreenCo as an efficient way to blend public and private sector finance in support of the development of Africa's power sector. With special thanks to Joan Larrea, Chris Clubb, Dean Segell and Trang Tran.



Africa GreenCo as a concept was included in the recommendations section of the SEforALL Finance Committee Report which was presented to Africa's Heads of State in Addis Ababa on 13th July 2015 at the Financing for Development Conference. A special thank you to Rachel Kyte and two of her team members (Lori Kerr and Stacy Swann) for their invaluable support and feedback on the draft version of this Feasibility Study.



Africa GreenCo was honoured to be invited to present the concept at a side event co-hosted with the AfDB and The Rockefeller Foundation at COP22 in Marrakech in November 2016, the output of which was further validation of Africa GreenCo's ability to help create a liquid power market. Our special thanks go to Said Mouline (COP22 Head of Public Private Partnerships) and Iskander Erzini Vernoit (Project Manager, COP 22 Public Private Partnerships).



A special thank you to Bloomberg New Energy Finance (in particular to Michael Liebreich, William Young and Lela Jgerenaia) without whose FiRe competition the Africa GreenCo concept would not have been born. The FiRe competition and the invaluable support of Michael, William and Lela encouraged Ana Hajduka the founder of Africa GreenCo to pursue the development of the concept.

Concept Supporters, Reviewers and Feedback Providers

Africa GreenCo is extremely grateful for the invaluable support and feedback received from the individuals listed below in their personal capacities.

Abel Tella	CEO, Association of Power Utilities of Africa
Abyd Karmali	Managing Director, Climate Finance at Bank of America Merrill Lynch
Alan Apter	Chief Financial Officer, Eaglestone Advisory
Alex Rugamba	Director of Regional Integration, AfDB
Alexis Faury	Financial Advisory, Resources and Energy Infrastructure, EC Energy Pte Ltd
Ana Corvalán	Managing Director, Eaglestone Advisory
Andrew Gray	Senior Legal Consultant, Trinity International LLP
Andrew Reicher	Chairman of Berkley Energy Africa
Andy Herscowitz	Coordinator, Power Africa
Anne Baldock	former Global Head Energy & Infrastructure Allen & Overy
Arnaud Dornel	Lead Financial Sector Specialist, World Bank
Arthur Smith	President, US National Council for Public-Private Partnerships Chair
Batchi Baldeh	Senior Vice President, Africa Finance Corporation
Brer Adams	Senior Director, Global Infrastructure Hub
Brian Count	Chairman, Infraco Africa
Caitlin MacLean	Director, Innovative Finance, Milken Institute
Callixte Kambanda	Chief Infrastructure Specialist, Secretariat of Infrastructure Consortium for AfDB
Carlos Salle Alonso	Director of Energy Policies, Iberdrola Group
Changala Nswana	Director of Strategy and Corporate Services, ZESCO
Cheikh Bedda	Director Infrastructure & Energy, African Union Commission
Chris Antonopoulos	Chief Executive Officer, Lekela Advisors Ltd
Chris Knowles	Head of Climate Change & Environment Division, EIB
Conal Duffy	Vice President, Emerging Markets, Alliant
Crispin Holliday	Commercial Director, Aldwych International
David Baxter	International Development and PPP Specialist and Facilitator
David L. Massie	Chairman & Chief Executive Officer of IAF Capital
David Munene Mwangi	Former KPLC Director
David Nelson	Executive Director, Energy Finance, Climate Policy Initiative
Elijah C. Sichone	Executive Secretary, Regional Electricity Regulators Association of Southern Africa
Eivind Fjeldstad	Managing Director, Norwegian African Business Association
Faruk Yusuf Yabo	Assistant Director, Department of Renewable Energy and Rural Power Access, Nigerian Federal Ministry of Power, Works and Housing
Felice Zaccheo	Head of Unit, Sustainable Energy and Climate Change, DG DEVCO, European Commission
Franklin Amoo	Partner, Aristeia Global Advisors / Baylis Emerging Market
George Kotsovos	Director: Mining, Energy & Infrastructure Finance, Standard Bank
George Otieno	CEO at African Trade Insurance Agency
Georgios Pantoulis	Head of Sector – Energy, DG DEVCO, European Commission
Gurdeep Singh	Chairman and Managing Director, NPTC Ltd
Harald Hirschhofer	Senior Adviser, The Currency Exchange Fund (TCX)
Helena McLeod	Head of KPMG (IDAS)
Ian Allison	Global Head Climate Resilience, Mott MacDonald
Isabel Rial	Senior Economist, Expenditure Policy Division, Fiscal Affairs Department, IMF
James Bond	Senior Advisor to the Executive Director of the Green Climate Fund and former COO of MIGA
Jan Martin Witte	Director, KfW Entwicklungsbank
Jean Madzongwe	Transaction Advisor, SAPP Project Advisory Unit
Joao Duarte Cunha	Chief Climate Finance Officer, AfDB
Jocelyn Wessling	Independent Consultant
John Smelcer	Head of Energy & Infrastructure, Webber Wentzel
Jonathan Berman	Managing Director, Fieldstone Africa

Jonathan First	Head of Syndication Finance, DBSA
Josh Chifamba	Group CEO, ZESA Holdings and Chairman of the SAPP Executive Committee
Katherine Steel	Energy Sector Team Lead, Power Africa
Professor Kevin Urama	Senior Policy Advisor on Inclusive and Green Growth to the President of the AfDB
Lori Kerr	Sustainable Energy for All
Lucy Heintz	Partner, Actis
Lynn Campo Tabernacki	Deputy Vice President, SME Finance and Head of Global Energy, OPIC
Michael Feldner	Renewable Energy Project Finance Advisor
Michael Liebreich	Chairman of the Advisory Board, Bloomberg New Energy Finance, and Member of the High Level Advisory Group, SEforALL
Michael Mulasikwanda	Principal Power Development Officer, Department of Energy, Zambia
Sir Malcolm Bruce	UK Member of Parliament and former Chair of UK International Development Select Committee
Marcus Williams	Acting Sector Manager & Lead Operations Officer - Energy and Extractive Industries, MIGA
Mariana Sabates Cuadrado	Government Finance, Statistics Division, IMF
Markus Faschina	Senior Energy Project Manager (Morocco), KfW
Mohamedain Seif Elnasr	Chief Executive Officer ad.interim of the Regional Association of Energy Regulators for Eastern and Southern Africa (RAERESA).
Mutale Mukuka	CFO, Copperbelt Energy Corporation Plc
Nchena Mothebe	Chairman of the SAPP Management Committee
Ntlai Mosiah	Head, Power & Infrastructure SA, Client Coverage, Standard Bank
Oscar Sibote Kalumiana	Director, Department of Energy, Zambia
Pankaj Gupta	Global Head, Project Finance & Guarantees, World Bank
Paolo Cravolatti	Climate Change and Renewable Energy, KPMG
Paul Maseli	Director and UNIDO Representative to the UN
Peter Covelliers	Deputy Head of Division, Climate Change and Energy Division, EIB
Philippe Niyongabo	African Union Commission
Philipe Valahu	Chief Executive Officer, The Private Infrastructure Development Group
Prakash D Hirani	General Manager, NETRA NPTC Ltd
Rentia van Tonder	Head of Power, Standard Bank
Robert Ashdown	Senior Originator Energy, Vice President, Products & Global Markets, Swiss Re
Richard Temple	Co-Head of Africa, McCarthy Tétrault
Roger Garman	Investment Analyst, Sustainable Development Investment Partnership (SDIP), World Economic Forum
Roman Zhukovskyi	Alternate Executive Director: EDS19, World Bank
Rumundaka Wonodi	Chairman & CEO, ZKI Energy Partners Limited
Ryan Anderson	Head of Renewable Energy advisory services at Multiconsult/NORPLAN
Sakkie Leimecke	Head, Energy E&T Nedbank Corporate and Investment Banking
Sarah Lawan	Senior Programme Officer, NEPAD Planning & Coordinating Agency
Simon Currie	Global Head of Energy, Norton Rose Fulbright LLP
Simon Hall	Former Co-Head of Finance, Freshfields Bruckhaus Deringer LLP
Shiddika Mohamed	Group Director, EnergyNet
Sofia Sattarova	Partner, Baker Botts LLP
Stacy Swann	Sustainable Energy for All
Steven Grin	Managing Partner at Lateral Capital
Steve McCauley	Executive Leadership Coach
Taylor Ruggles	Regional Energy Counselor for Africa, U.S. Department of State
Titus Chongo Mwandemena	Chief Commercial Officer, Copperbelt Energy Corporation Plc
Tom Heller	Chairman of the Board and Senior Strategic Adviser, Climate Policy Initiative
Vibhuti Jain	Financial Solutions Lead, Power Africa
Vivek Mital	Managing Director, Millennium Resource Strategies
Vivek Shinde Patil	Senior Manager, Technical Applications, PerkinElmer
Vladimir Maodus	Executive Director, CEE Investment Banking
Wendy De La Harpe	Conference Producer, African Utility Week
Zahed Sibda	Managing Director, Fieldstone Africa



Africa GreenCo Team

Ana Hajduka	Founder & CEO
Cathy Oxby	Commercial Director
Lovemore Chilimanzi	Technical Director
Penny Herbst	Non Executive Director
Tantra Thakur	Advisory Committee Member
Philippe Niyongambo	Advisory Committee Member
Rt Hon Andrew Mitchell MP	Advisory Committee Member

Africa GreenCo in its current form is a UK not-for-profit company limited by guarantee which has been established with the sole purpose of developing the AGC concept to its pre-implementation stage. This UK entity is entirely separate to the operational AGC entity discussed elsewhere in this report, which will be an African based entity, incorporated subject to political and international community buy in.

Consultants



Financial: Lions Head Global Partners

Lions Head is a specialized financial advisory firm based in London and Nairobi, experienced in designing, structuring innovative finance platforms, especially for power (Africa50, AREF, GIIF, TCIFF)

With special thanks to: [Harry Guinness](#)



Legal: Shearman & Sterling LLP

Sherman and Sterling is a leading international project finance, corporate and commercial law firms, active in Africa for over 50 years.

With special thanks to: [Monica Lamb](#)



Technical: PPA Energy

PPA's Energy's staff are former leaders within SADC utilities and have been involved with the SAPP establishment and operations (governance, regulations, technical constraints, commercial issues, trading etc)

With special thanks to: [Lovemore Chilimanzi](#)



Regulatory & Governance: GP3 Institute

GP3 Institute is a global advisory network of governance, development, legal and program operation advisors. The institute provides research and advisory support for public-private initiatives comprised of States, subnational units, multilateral development and finance institutions and private sector participants including for profit and non-profit organizations.

With special thanks to: [Tim Nielander](#) and [Ben Kioko](#)

Procurement: Rene Meyer (Senior Procurement and Renewable Energy Policy Expert)

Risk Management: Strategia Worldwide

Strategia Worldwide use proven strategic planning methodology to protect companies from risk in complex, volatile, uncertain environments and apply a comprehensive approach to corporate risk management, drawing on their experience of implementing strategy in dangerous and difficult environments and the political, developmental, security and commercial expertise of their highly experienced senior team.

With special thanks to: [Iain Pickard](#)

EXECUTIVE SUMMARY

This Feasibility Study proposes and evaluates a simple, yet fundamental change to the structuring of independent power projects in Sub-Saharan Africa, and to the way in which financial and credit support is provided to them.

It demonstrates the viability and effectiveness of aggregating offtaker credit risk into a single, creditworthy vehicle, and the lasting impact this will have in improving project bankability, reducing fiscal burden on host Governments, reducing project costs and development times, and increasing the availability of capital to the sector.

G reen
R egional
E nergy
E fficient
N ew and
C reditworthy
O fftaker
for Africa

Africa GreenCo (“AGC”) proposes to interpose a single creditworthy counterparty between buyers and sellers on multiple independent power projects (“IPPs”) in sub-Saharan Africa (“SSA”). Through its structure, AGC will mitigate the underlying credit risks associated with long term investment in the African power sector. Compared to current market practice this will:

- ④ reduce risk and project development costs for all stakeholders;
- ④ address inefficiencies caused by the current ‘single buyer single seller’ model;
- ④ reduce fiscal burden for host Governments; and
- ④ catalyse private sector debt and equity investment.

AGC responds to Sustainable Development Goal 7 which aims to close the energy access gap and “ensure access to affordable, reliable, sustainable and modern energy for all” through a combination of national action and international cooperation. AGC can act as an implementation tool for key regional initiatives, such as the African Development Bank’s New Deal on Energy for Africa and the Africa Renewable Energy Initiative.

In the long term, as AGC succeeds in attracting more private sector investment to the sector, at lower cost, and assists in the transition to cost-reflective tariffs and ultimately utility creditworthiness, AGC will make itself redundant in its role as a creditworthy intermediary. As this occurs, AGC will transition to being one of many traders on the Africa power markets it helps to develop. In the Southern African context the proposed AGC market intervention therefore fits neatly alongside the IPP framework being developed and implemented by RERA, the Regional Energy Regulators Association of Southern Africa, which aims to put in place the regulatory environment needed for an open and active regional power trading market.

Market Context

Bilateral IPPs	With the exception of a handful of cross-border projects, IPPs within SSA are currently structured on a bilateral basis; i.e., with a single buyer and seller.
Rehabilitation of utilities	African utilities are often poorly funded – running an operating loss due to non-cost reflective tariffs, high overheads and substantial investment needs. In most cases they are entirely state owned and dependent on budget transfers – all of which combine to mean a low credit profile. Critical steps to rehabilitate utilities are underway but sustainable and material improvements can only occur in the medium to long term.

Lengthy and expensive transaction execution	With notable exceptions such as South African REIPPP, GET FiT Uganda and Scaling Solar Zambia, IPPs are largely negotiated on an ad hoc project-by-project basis. Negotiations of project documents on individual IPPs are usually very lengthy and often last several years at least. Significant fully 'at risk' development costs incurred during those negotiations add materially to total project costs and require a high return to reflect the associated risk profile.
Limited availability, sustainability and effectiveness of third party risk mitigation instruments	Risk mitigants such as liquidity support instruments, early termination buyout regimes and partial risk guarantees are complicated and expensive to negotiate on a project-by-project basis. Even still, in their current guises they do not fully mitigate the perceived risk of investing in immovable assets in order to sell a commodity (electricity) on a long term basis to a single, often un-creditworthy, buyer.
Host Government fiscal burden	Host Governments are expected to take on contingent liabilities in the form of 'put and call option' arrangements on early termination, or more explicit sovereign guarantees. Given the current fiscal position and the medium term macro-economic environment facing most host Governments, this is unsustainable.

Sustainability of Current Market Context

The current project-by-project approach to supporting grid connected renewable energy IPPs in sub-Saharan Africa is unsustainable. Significant weaknesses of the current model include:

- ⌚ If an offtaker default leads to PPA termination, a single Generator does not have the contractual, regulatory or operational ability to 'trade out of' the position of losing its sole customer. In this eventuality, there is no expected alternative other than for the Generator to exercise the early termination buy-out provisions included in the transaction documents; i.e., to crystallise the host Government's contingent obligation to purchase the generation facility.
- ⌚ There is a limit to the fiscal burden which host Governments can prudently incur under early termination buy-out provisions. In various SSA countries, significant project delays (and associated project development costs) are already witnessed due to host Governments resisting additional fiscal burden. The current bilateral IPP model provides no solution to this.
- ⌚ Credit enhancement provided on a project-by-project basis typically adds significant cost and equally significant delays to transaction execution.
- ⌚ To the extent that DFIs take sovereign credit risk on their own exposures, they effectively create a 'closed shop' with each DFI financier accepting sovereign credit risk only in relation to debt or equity which it has provided. Although stand-alone credit support instruments are available, this bundling of finance with the acceptance of sovereign credit risk by DFIs puts private sector financiers at a significant disadvantage.
- ⌚ Even with multiple layers of DFI support and relatively high tariffs, renewable energy projects in SSA (outside of South Africa) are still not particularly attractive to private sector sources of capital. Project development times are often very long; fully at risk development costs incurred prior to financial close are usually very high; the risk of not reaching financial close is often very real and in any case much higher than it needs to be; project documentation and structures are cumbersome; and the prospect of making a claim against a host Government, with or without sovereign credit support, is a daunting one. This all leads to a market which is effectively inaccessible to all but a fairly small group of well-funded, sophisticated market participants, most of whom are either DFIs or are funded directly or indirectly by DFIs.
- ⌚ Although there have been notable attempts to standardize project documentation, e.g. via South African REIPPP, Scaling Solar, GET FiT Uganda and now GET FiT Zambia, the predominant model is of bespoke negotiation of project agreements on a project-by-project basis. Lessons learnt are not sufficiently crystallized into accepted principles and practices, and there is an unacceptable degree of 'reinvention of the wheel' on successive projects, as well as on similar projects in different countries. In some markets (particularly in relation to some REFIT programs in the region) the standardized documentation proposed is very clearly unbankable under conventional project finance principles.

Precedent

AGC aims to learn from, and where possible replicate, the dynamics of more advanced power markets, in particular building on the experience of the Power Trading Corporation of India (PTC India). PTC India was also set up in order to act as a credit risk mitigating intermediary offtaker for privately-financed regional power generators. In the process, it catalysed the entire Indian regional power sector trading market. For a full overview of PTC India please see [Section 2 \(Precedent for Power Sector Intermediary – PTC India\)](#).

Strategy

AGC addresses head on the core issues of (a) offtaker creditworthiness, and (b) the inefficiencies of exclusive bilateral sale and purchase between a single generation company and a single offtaker.

The first conceptual step is to interpose AGC between the buyer and the seller under an existing bilateral IPP structure; then repeat this on multiple IPPs so that:

◎	AGC is the buyer for multiple generation companies; and
◎	AGC is the seller for multiple offtakers.

From this position, AGC will be able to:

- ◎ divert power from a defaulting IPP offtaker to other willing buyers, thereby reducing the likelihood of early termination of an IPP's power purchase agreement, and the resulting crystallisation of host Government contingent liabilities¹;
- ◎ catalyse third party private capital flows to IPPs by improving the risk profile of projects in the region;
- ◎ lower the required electricity tariff by reducing the return requirements of investors to reflect a lower risk profile; and
- ◎ provide a route to market for any excess contracted power, thereby mitigating an offtaker's obligation to pay capacity or 'deemed energy' charges for capacity that they do not require.

More broadly, AGC will:

- ◎ be fundamentally better equipped than a single generation company to mitigate the effect of an un-creditworthy and/or defaulting offtaker;
- ◎ also act as a power trader, thereby increasing liquidity and scale of regional power trade;
- ◎ assist in the development of power pools;
- ◎ support and promote regional standardisation of IPP project documentation; and
- ◎ assist in the development of fair and standardised electricity markets in the countries in which AGC operates.

AGC will act as intermediary offtaker only and would not manage the physical transmission and distribution of energy. It would not own any of the grid infrastructure or seek to replace existing utilities. Rather than replacing existing structures, it complements them, and can further act as a bridge to any future energy regional market liberalization and energy trade integration.

Design Principles and Structure of AGC

AGC will implement this operating strategy within an entity that combines the following overarching characteristics:

Prioritises political and financial ownership by African governments – in line with recently established bodies such as ARC, Africa50, ATI and AFC.	Attracts investment from the development finance community and international and local commercial investors.
Balances its public-private ownership and partnership approach with a commercially managed, financially sustainable operating model.	Is able to operate as a legally and financially creditworthy offtaker across African power markets.

¹Preference will be given to supplying alternative purchasers in the same country, for example by selling direct to the customers of the defaulting offtaker, such that end users are not impacted. The proceeds of sale will offset the defaulting offtaker's payment obligations to AGC.

The AGC concept has been developed to fulfil the following key design principles:

◎	Legally and financially creditworthy
◎	African-owned and African-led
◎	Financially sustainable
◎	Scalable
◎	Facilitating cross-border trade and investment
◎	Complementing and collaborating with existing initiatives
◎	Benefiting IPP investors, utilities and sovereigns
◎	Catalysing private sector capital
◎	Incorporating blended capital from concessionary and commercial sources

AGC's role in the African power markets

AGC will play two complementary and synergistic roles in the African power markets:



AGC as an intermediary offtaker and aggregator

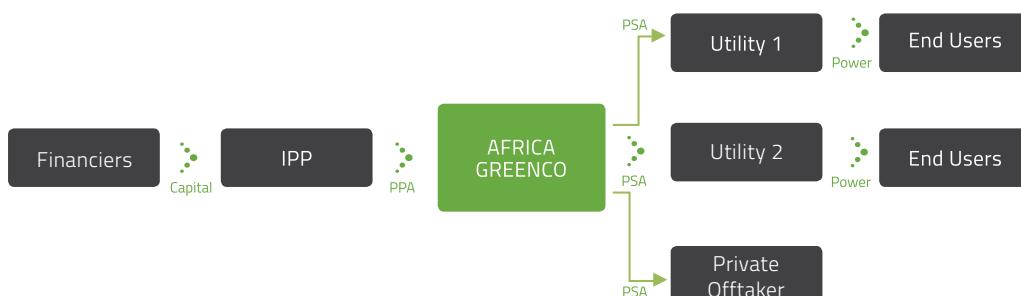
The following is a simple single utility offtaker example:



AGC will purchase capacity and energy from the IPP under a power purchase agreement ("PPA"), and sell that capacity and energy to the utility under a power supply agreement ("PSA"). The PPA and PSA will be on largely back-to-back terms; **save that**:

- ◎ AGC will take credit risk on the offtakers, such that upon offtaker default under the PSA, AGC will have the contractual, regulatory and operational ability to keep the PPA 'alive' by securing alternative buyers whether on a bilateral basis or through short term trading, and will use all reasonable efforts to do so;
- ◎ AGC will earn a small margin between the tariff paid under the PPA and the tariff received under the PSA.

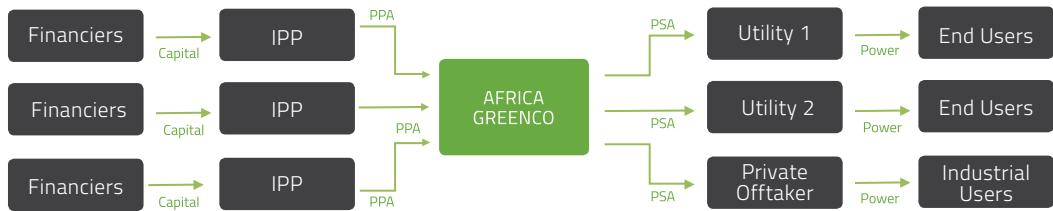
The following is an example of a more complex multi-buyer project, which may be suitable for larger IPPs and/or cross-border projects.



In the above scenario, the intervention of AGC will allow:

- ⑤ individual offtakers to commit to purchase only a portion of the IPP's total capacity; and
- ⑤ AGC to better manage the complex risks arising under, and documentation required for, multi-offtaker structures.

This structure will be repeated on multiple projects, building a portfolio of IPPs on one side and a portfolio of Offtakers on the other. The portfolio effect will diversify AGC's risk and enable it to source alternative power or offtakers (as the case may be) in case of default under either a PPA or a PSA.



AGC as a Power Trader

In addition to its role as an offtaker, Africa GreenCo will also participate in the competitive power markets, promoting cross border power transactions and a more dynamic and liquid short term power market.

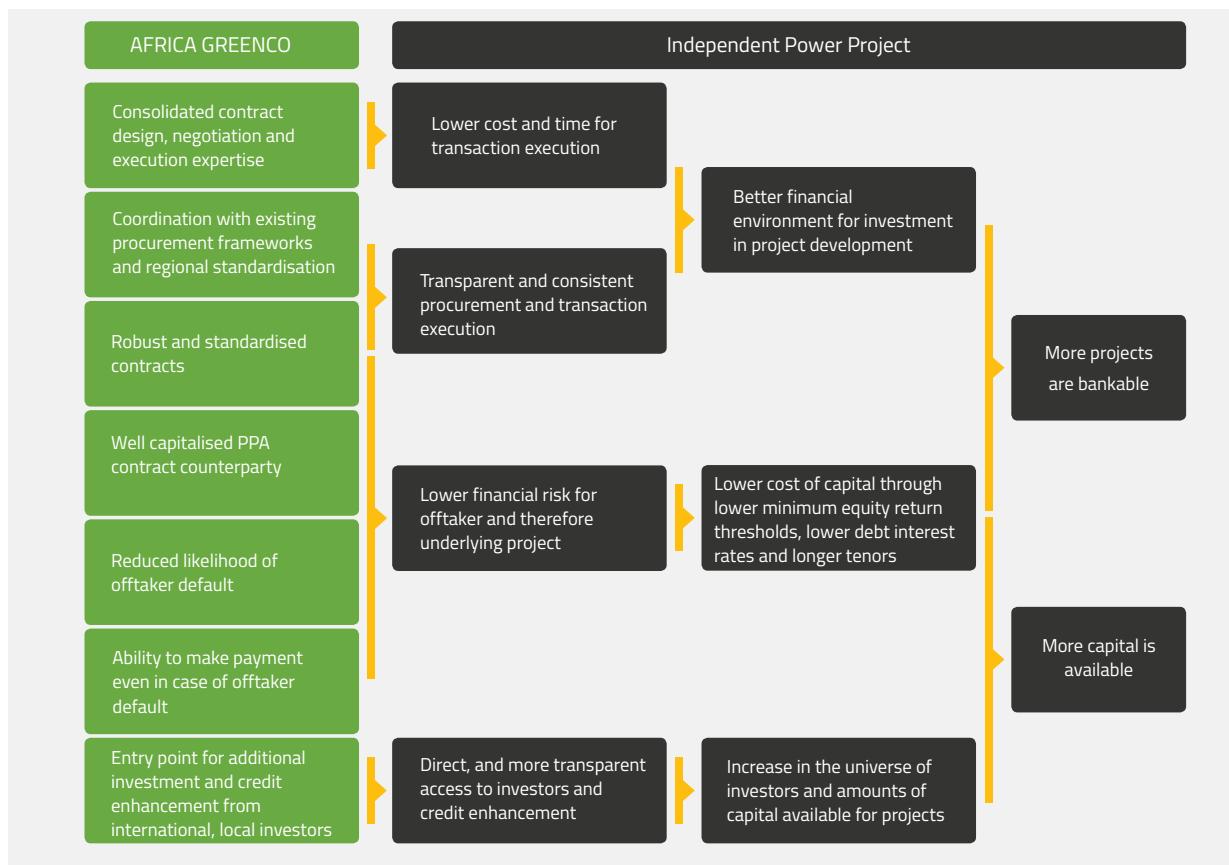


Impact of AGC on Project Companies

AGC provides the project company with a counterparty which (a) is creditworthy, (b) can mitigate risk via diverting power to third party customers, and (c) can diversify risk over multiple projects.

The intervention of AGC is expected to:

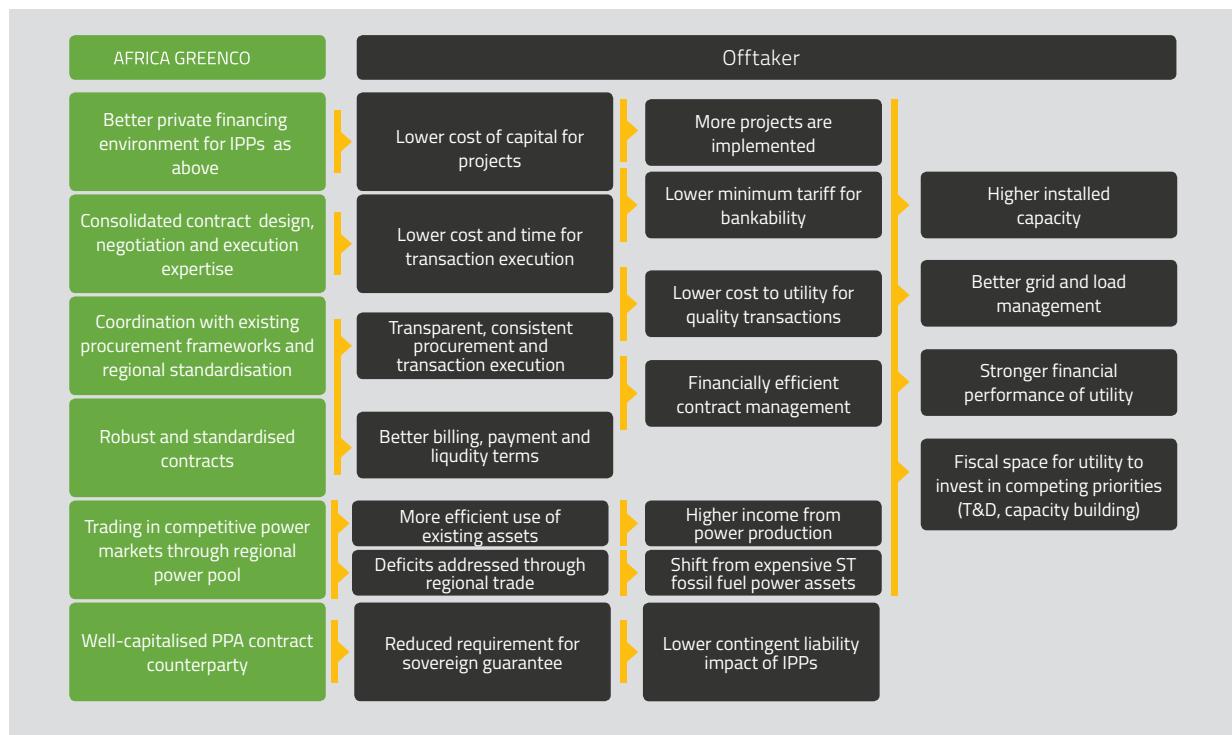
- ⑤ reduce both total project costs and the cost of capital by:
 - reducing the cost of getting projects to financial close;
 - improving projects' credit risk profile and in turn:
 - reducing equity investors' hurdle IRRs;
 - reducing the interest rates and other covenants such as debt service cover ratios on project debt; and
 - increasing the tenors of project debt;
- ⑤ make investing in, and lending to, African IPPs (whether at the outset or upon a refinancing) attractive to a wider pool of capital than is currently engaged in the market, in particular to private sources of capital, thereby increasing the available pool of capital; and
- ⑤ allow for more efficient and effective credit enhancement, by building a portfolio of contract exposures which can be de-risked and/or re-insured on a pooled basis.



Impact of AGC on Offtakers and Host Governments

AGC will:

- ④ reduce the financial expense and utilisation of human resources incurred by the host Governments and offtakers in negotiating and executing IPP transactions;
- ④ increase the installed capacity in the power system, facilitating more reliable power supply to end users;
- ④ reduce PPA tariffs (on new IPPs) due to lower IPP development costs and cost of capital;
- ④ lower the average cost of delivered power by utilizing otherwise idle generation capacity for generation and sales to third parties, and offsetting the revenue received from third party customers (less a small margin) against deemed energy charges otherwise payable by the Offtaker;
- ④ help substitute short term emergency power with cross border traded power;
- ④ reduce the fiscal burden on host Governments by reducing the probability of early termination buyout obligations or more explicit host Government guarantees being crystallised, and in certain eventualities reducing the quantum of such obligations;
- ④ reduce risk-weighted capital adequacy requirements in relation to loans to the power sector creating additional debt capacity which can be used to fund sectoral improvements;
- ④ create fiscal space and release Offtaker resources to focus on institutional capacity building, operational efficiency improvements and expansion and upgrades to transmission infrastructure; and
- ④ facilitate the move towards local currency denominated PPAs.



AGC's key mitigants in relation to offtaker risk are:

Trading power in case of default	AGC's position as an intermediary offtaker allows it to sell power to alternative buyers in case of offtaker default. From the Generator's perspective, incoming payments from AGC will occur regardless of Offtaker default. If AGC is unable to sell power to an alternative buyer for the same price as the PPA contract or is not able to sell the power at all, AGC will seek to recover such losses from the defaulting Offtaker, initially by applying any payment security provided by the Offtaker.
Capitalisation	If the payment security provided by the Offtaker is exhausted and no alternative long term offtaker has been found and the Offtaker is an SOE, AGC may apply the equity contribution of the host Member state of the defaulting Offtaker in satisfaction of losses suffered by AGC as a result of the default. If this is still insufficient to cover AGC's losses and enable it to continue to make payment when due under the PPA, and it in fact defaults under the PPA and a termination payment becomes due, AGC's capitalisation and guarantee structure means that any applicable termination payment can be made. In the financial model, the full termination exposure across AGC's PPA portfolio is capitalised through equity/leverage for exactly this reason. It is however extremely unlikely that a default would occur under all of AGC PSAs. If AGC has recourse to the sovereign's shareholding in AGC in case of default this creates a secondary contingent liability. However, AGC's operating model and capital structure makes the probability of drawing on that contingent liability minimal. As a result, even if AGC has recourse to sovereigns against defaults under their control, AGC is a highly efficient fiscal management tool from the IMF perspective.
Aligned incentives	Despite the apparent exposure this creates for AGC against termination payments, the strategy of including/requiring beneficiary governments in AGC's capital structure creates added disincentives to default, including: (i) such default will be widely known by the other Members of AGC, including neighbouring countries and MDBs/DFIs, (ii) there could potentially be an impact on any other funding sources provided by the participating MDBs/DFIs to the relevant country and (iii) AGC's financial performance will suffer and the value of that shareholding will be impaired.

Regional Impact of AGC

AGC will:

- ④ actively trade power in the competitive markets established within the existing power pools (SAPP, WAPP, EAPP etc), increasing liquidity and efficiency;
- ④ be able to disaggregate the contractual supply of electricity from the physical flow of electrons²;
- ④ work with power pools, member states and utilities to match power surpluses and deficits, and to maximize the efficient use of natural resources on a regional basis³;
- ④ support efforts to integrate planning, power sector regulation and infrastructure investment across member states; and
- ④ help to build the financial and economic case for more investment in regional transmission, interconnection and grid management by increasing traded volumes.

Benefits for projects and investors

Taken together the potential impact of AGC in power markets is substantial. Each dollar invested under a 33% equity scenario generates \$5-\$6 additional financial benefit that is directly quantifiable. The operating model helps to unlock enough capacity to connect almost one million households to the grid and avoids 7m tonnes of carbon equivalent, while generating over 20,000 new skilled jobs. The table below provides a more detailed breakdown of these impacts with the total value split out over each different investor class. In terms of private sector capital, the model forecasts that AGC will be able to unlock an additional USD 1.31bn of investment in IPPs, which is a conservative estimate as it is based on no private capital incentivised through AGC's trading activities.

Impact Per USD Invested in AGC by yr 10		Total USD Impact		Investment		Contingent Liabilities		Tariff Savings		Trade		Power		Additional Impacts	
		Low	High	Total	Total	Low	High	Mid	High	Total	Total	Inst. Capacity	Power Output	GWk	
100% Equity	Investment			USDm	USDm	USDm	USDm	USDm	USDm	USDm	MW				
Total	1,360	USDm	1.5	2.0	1.0	0.9	0.2	0.7	0.1	0.2	0.2	0.4	Power Traded		
Donor	680	USDm	2.9	4.1	1.9	1.7	0.4	1.3	0.2	0.5	0.4	0.7	2,943,374 MWh		
African Gov't	408	USDm	4.9	6.8	3.2	2.9	0.7	2.2	0.3	0.8	0.6	1.2	Electricity Access		
DFI/Private	272	USDm	7.3	10.2	4.8	4.4	1.1	3.3	0.5	1.1	0.9	1.8	970,000 Hholds		
50% Equity															
Total	680	USDm	2.9	4.1	1.9	1.7	0.4	1.3	0.2	0.5	0.4	0.7	Carbon Emissions		
Donor	340	USDm	5.9	8.1	3.9	3.5	0.9	2.6	0.4	0.9	0.8	1.4	7,800,087 tCOe		
African Gov't	204	USDm	9.8	13.6	6.4	5.8	1.5	4.4	0.7	1.5	1.3	2.4			
DFI/Private	136	USDm	14.7	20.3	9.6	8.7	2.2	6.5	1.0	2.3	1.9	3.6	ST Employment		
33% Equity															
Total	449	USDm	4.4	6.2	2.9	2.6	0.7	2.0	0.3	0.7	0.6	1.1	22,655 Jobs		
Donor	224	USDm	8.9	12.3	5.8	5.3	1.3	4.0	0.6	1.4	1.1	2.2			
African Gov't	135	USDm	14.8	20.6	9.7	8.8	2.2	6.6	1.0	2.3	1.9	3.6	LT Employment		
DFI/Private	90	USDm	22.2	30.8	14.6	13.2	3.3	9.9	1.5	3.5	2.9	5.4	1,014 Jobs		

²By way of example:

- AGC is contractually interposed between a Generator and an Offtaker ("Offtaker X") which are within a given county but either (i) physically a long distance apart, and/or (ii) connected via electricity transmission lines which are congested; and
- AGC has also contracted with another Generator which may or may not be in the same country as Offtaker X, but which is (i) physically closer to Offtaker X, and/or (ii) connected to Offtaker X via an uncongested transmission line, then to the extent that this other generation company has excess capacity, AGC will be able to physically supply Offtaker X from the other generation capacity.

When the above example is extrapolated across all portfolio projects and countries, AGC expects to be able reduce both (a) line losses (thereby reducing the delivered cost of electricity), and (b) the negative impact of grid constraints, by finding the most efficient physical flow of electrons.

³While AGC cannot create electricity demand which does not exist, once it has built a portfolio of Offtakers across several countries, including both utilities and large industrial customers, and is also established as a trader of electricity, AGC will be much better placed than a national utility offtaker to find spot and/or short term buyers for capacity which would otherwise be sitting idle under the bilateral IPP model; i.e., to match idle supply with excess demand.

Environmental, Employment, Social and Economic Impact

AGC will:

- ⌚ avoid 9.3m tCO₂e emissions in 10 years and more than 70m tCO₂e emissions over the life of the PPAs⁴;
- ⌚ help create over 22,000 temporary jobs in manufacturing, construction and installation over the first ten years of operations and over 1,000 long term O&M jobs by year 10⁵;
- ⌚ create additional employment as a consequence of access to more reliable power and savings relative to emergency power costs with a particular impact on small and medium size enterprises, such as women's cooperatives;
- ⌚ improve access to basic services such as healthcare and education through improved electricity access;
- ⌚ stimulate socio-economic development, including reducing infant and maternal mortality rates, improving literacy and facilitating community-based activities and training; and
- ⌚ help avoid the economic impact of outages that can be as high as 4% of GDP⁶ and result in an average annual "drag" on economic growth of 2%⁷.

Target Market

In order to test the long term feasibility of the proposed intermediary, we have constructed a hypothetical portfolio of 10 projects. The choice of projects was informed by technical analysis of the prevailing environment within the existing power pools in SSA. While AGC is equally applicable to all power pools, we have focused on the Southern Africa Power Pool for the purposes of the Feasibility study.

Some of the projects in the portfolio reflect specific projects in the pipeline identified by AGC's technical advisors. Others are derived from conversations with developers and utilities about the type of mid-size renewable energy projects that they envisaged coming to market over the next five years or identified using the Power Africa Tracker Tool. Most initiatives, for example, Power Africa, ElectriFi, IRENA, and SEFA, forecast a large number of small-medium power projects coming to market over the next decade. Key characteristics of the initial target projects are:

- ⌚ within the member states of the Southern African Power Pool
- ⌚ between 5-100MW
- ⌚ grid-connected

To understand the relationship between AGC, IPPs and the financiers – equity and debt – funding those IPPs, we have prepared a condensed project finance model for each project in the AGC hypothetical portfolio. Using international benchmarks, assumptions have been made regarding construction and operating costs and power output per technology type and assumed tariff based on project size.

Operating Strategy

AGC's operating strategy creates four potential revenue sources for AGC:

- | | |
|---|---|
| ⌚ | Sale of power purchased under long term agreements; |
| ⌚ | Sale of power on short term trades; |
| ⌚ | Income from invested capital; and |
| ⌚ | Sale of carbon credits. |

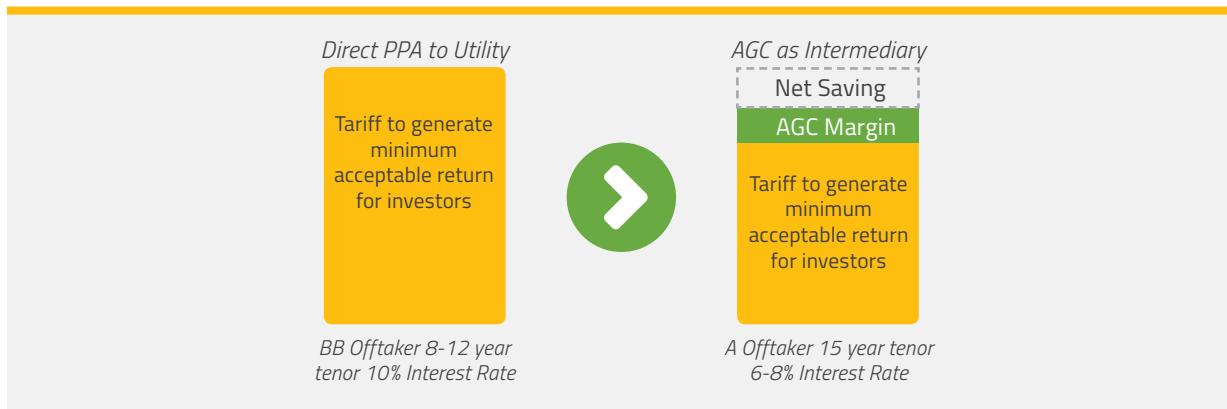
⁴Based upon AGC's hypothetical project portfolio applying CDM 2013, Standardized baseline: Grid emission factor for the Southern African Power Pool, and country-specific GEFs from UNFCCC.

⁵Calculated based upon IRENA (2016), 'Renewable Energy Benefits: Measuring The Economics'. IRENA, Abu Dhabi.

⁶Africa Infrastructure Country Diagnostic: Underpowered: The State of the Power Sector in Sub-Saharan Africa", Eberhard, Foster et al., 2008

⁷'Power Outages and Economic Growth in Africa", T. Barnebeck Andersen and C. Dalgaard, Discussion Papers on Business and Economics No. 7/2012

AGC's two core operating activities – acting as a PPA offtaker and short term trading - will generate revenues through a margin applied to each unit of power bought and sold. This margin may vary based on the specifics of the actual projects AGC supports. For its role as a PPA offtaker selling power on to utilities/other offtakers through a PSA, AGC aims to select a margin level that generates a net reduction in the price of power paid by a utility/ofttaker.



For short term trading, the AGC base model takes a conservative assumption of 10% p.a. growth of the SAPP Day-Ahead /Intra-Day markets and applies an estimated market share for AGC of 5% in year 1, growing to 20% from year 4.

Funding Requirements

In assessing how AGC might be financed to implement the proposed operating model, this Feasibility Study considers how much capital AGC will require in order to:

- ④ fund operating costs before AGC becomes cash-flow positive;
- ④ have sufficient liquidity to enter into and deliver on trading and purchase/sale contracts; and
- ④ be perceived as a creditworthy offtaker.

The analysis includes a Monte Carlo simulation of the probability of defaults arising within AGC's portfolio and suggests that:

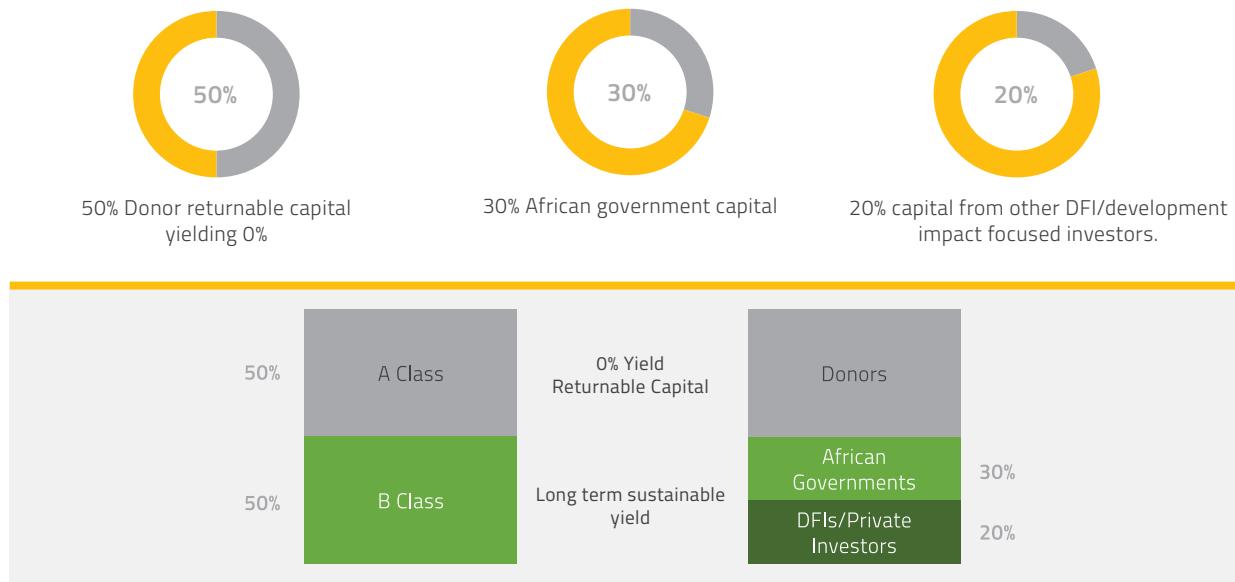
- ④ AGC's equity base should equal 33% of its maximum exposure (being predominately the termination payments which could arise under its PPAs) to be sufficiently creditworthy (investment grade);
- ④ the remaining exposure could be uncovered or covered through guarantees and/or insurance. AGC is working with potential guarantee and insurance providers such as ATI, MIGA and commercial insurers to explore means of leveraging AGC's equity; and
- ④ the capital structure will draw down additional funds as needed to backstop new exposures created by growth and/or recycle retained earnings to build a robust balance sheet.

The recommended equity structure is a trashed model, with distinct share classes for different investor classes. The main reasons for this are to:

- | | |
|---|--|
| ④ | Promote African ownership and political alignment with AGC's strategy; |
| ④ | Return capital to investors in different ways; |
| ④ | Accommodate donor investors; and |
| ④ | Allow investors to contribute capital using different instruments. |

The size and terms of each tranche will ultimately be determined by investor feedback on appetite and capacity to deploy capital. The capital structure will likely evolve over time as the AGC strategy is proven and adapted to the realities of doing business on the ground.

The simple trashed structure proposed for AGC is:



This structure creates a 50/50 split between capital with no upside and capital that generates returns – the exact ratio can be adapted depending on what investors are looking for in terms of yield; if the market feedback is that investors are seeking higher returns, the proportion of returnable capital can be increased (or else the price and volume of the power traded will need to increase on the same capital base). If investors are willing to take more risk and lower returns, the capital structure can be weighted to allow them a greater share and reduce the donor returnable capital tranche.

It is proposed that tranched equity is sourced from some or all of:

- ④ African governments seeking to participate in order to play a direct role in driving and owning the AGC concept;
- ④ donors/equivalent grant and concessional capital providers seeking to catalyse private sector investment in the African power sector;
- ④ DFIs active in African power sector looking to promote innovative, market-based solutions for improving the environment for commercial investment and risk mitigation;
- ④ impact investors and philanthropic organisations (e.g. Foundations, NGOs) seeking to contribute to developmental impact through mission-related investment; and
- ④ strategic commercial capital, institutional investors and venture capital investors seeking market rates of return.

Financial Results

In terms of fundamental financial performance, AGC has a limited, but long term financially sustainable return under a 33% equity/ 67% leverage scenario. With (a) 50% of such equity comprising non-interest/dividend-bearing returnable capital, and (b) a USDc 0.3/kWh margin on power sales, the model shows concessional returns of c.2.8% on the remaining equity and protection of capital; however, the return profile and long term financial sustainability of AGC may be enhanced either by increasing the margin (noting the material tariff reduction expected to be caused by AGC), or for certain classes of investors via tranching.

The process for setting margins should be transparent and operate in collaboration with the key regulators and utilities, but one reasonable input may be selecting a target that is able to attract sufficient capital into AGC (and future trader/intermediary market entrants). AGC is more likely to attract sufficient capital (from a wider universe of investors) if the Class B shareholder IRR is e.g. 6% versus 2.8%. Using illustrative numbers and assuming a 33% equity base, investors can increase IRRs to 6% by increasing the PPA margin to USDc 0.7/kWh or higher. That would be comparable to other impact investment and development finance vehicles. To achieve returns of 10% or more, AGC would need to charge PPA margins of USDc 1.2-1.5 kWh. The margin AGC is able to charge will also be a factor of the reduction in PPA tariffs which AGC can achieve.

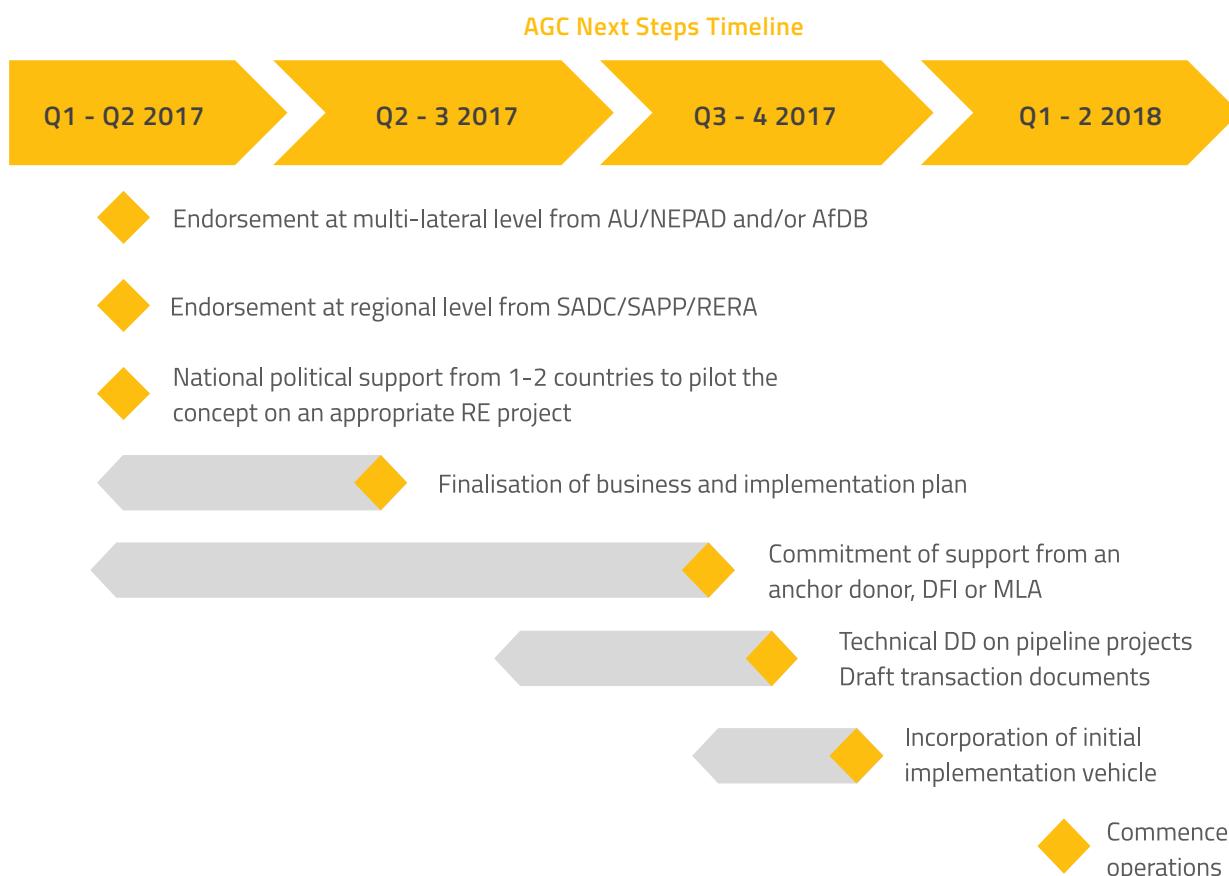
Conclusion and Next Steps

Based on the analysis contained in this Feasibility Study, AGC represents a financially viable means of helping more projects achieve bankability and bringing larger volumes and new sources of capital to African power markets. AGC can also help streamline African utilities' engagement with IPPs, reduce the time and effort required to bring transactions to close, relieve the burden of providing sovereign guarantees and, in the process, help to create the space necessary to implement measures to achieve long term creditworthiness of African utilities and improve domestic power markets. However, many concrete details in terms of the legal structure, governance, operating model, capitalization and financial performance require ongoing feedback from potential investors and promoters of the concept. AGC has garnered significant momentum and interest in the African and international development community. That momentum may require quick action to pilot the AGC concept and it is anticipated that AGC's business will need to be trialled in a small number of countries initially in order to prove the model before being rolled out across the region and continent.

Political will and endorsement by African institutions such as the AfDB, AU and relevant regional entities (e.g. SADC, SAPP and RERA in the Southern African context) should significantly accelerate this process.

Beyond the strategic activity required to manage and grow this political support, AGC also plans to refine its business case, transitioning from the Feasibility Study's assessment of whether or not the concept has merit to more detailed and structured approach on how the concept will be implemented. The key components of this will include:

- ④ supplementing AGC's team to include additional expertise to take the concept to market;
- ④ creating the legal structures required to execute the operating model in AGC's target geographies;
- ④ finalising AGC's operating policies and procedures, governance structures and transaction documentation;
- ④ identifying suitable projects for proof of concept;
- ④ pursuing SAPP membership;
- ④ preparing a business case and additional investor outreach materials; and
- ④ refining the concept with a small number of potential anchor investors and other stakeholders.



STRUCTURE OF THIS FEASIBILITY STUDY

This Feasibility Study explores the main considerations for implementing the AGC strategy, the financial viability of the concept and the potential impacts – qualitative and quantitative – that may result. The study is divided into nine sections.

Section 1 discusses the **alignment** of the AGC concept with other international and regional initiatives.

Section 2 outlines the key **precedent** for such a creditworthy intermediary offtaker, namely the example of PTC India.

Section 3 describes the **market context** of the main issue that AGC seeks to address, namely, offtaker creditworthiness. The section reviews how offtaker creditworthiness affects IPPs, what the main drivers of offtaker creditworthiness are and the landscape of utilities in sub-Saharan Africa today. This section also reviews how the market currently addresses the challenge through a range of credit enhancement instruments.

Section 4 describes the **potential target markets for AGC**. The section reviews the physical structure of power generation and transmission and distribution networks, provides information on the expected pipeline of projects, highlighting specific projects that AGC will be able to support, and describes how both long term and near term market conditions should be considered in selecting pilot projects. Finally, the section sets out the cross-border power trading context.

Section 5 provides **financial analysis of AGC's intermediary role and trading strategy**. The section constructs a hypothetical portfolio of projects for AGC's initial operating period and uses this to assess AGC's financial viability, contextualizing pricing and volume for long term power contracts and short term power trading. It then analyses the costs and capital required to achieve those revenues – both the costs of implementation and the financial implications being a creditworthy contractual counterparty. The section then describes how financial support for AGC can be efficiently structured and, finally, the relationship between AGC's operating parameters, capital structure and financial performance.

Section 6 reviews the **impacts and benefits that AGC brings** – with quantitative estimates where possible. It analyses the benefits to (i) private sector stakeholders in the African power market, (ii) the utilities and sovereigns within potential AGC target countries and (iii) the broader impact on energy access, economic development, climate change and sustainability.

Section 7 describes **the key contractual relationships** for IPPs, Offtaker and host governments and how AGC will be incorporated into those relationships. The analysis includes a detailed review of the allocation of key risk under PPAs and PSAs and how AGC will manage such risks as well as considering AGC's potential role in procurement.

Section 8 describes a number of options with respect to **AGC's corporate structure, governance and risk management**. It considers various legal structures that may be appropriate for AGC, drawing on those adopted by comparable development finance initiatives. The section then reviews how governance and decision making can be tailored to balance the interests of AGC's stakeholders and shareholders, assuming AGC is implemented as a public-private partnership between donor governments, African governments, DFIs and private investors.

Section 9 sets out the key decisions and **next steps** towards implementation.



1 Alignment with other international and regional initiatives

1.1. Alignment with international climate agenda and other African regional initiatives

The Africa GreenCo structure has been inspired by existing initiatives and developed to ensure alignment with them in order to ensure the most efficient deployment of resources to help convert Africa's huge energy potential into light and power for the hundreds of millions who need it. As stated by the Africa Renewable Energy Initiative, transformational change is both needed and possible but it must be stimulated by truly collaborative international efforts and goodwill.



AGC responds directly to Sustainable Development Goal 7 which aims to close the energy access gap and "ensure access to affordable, reliable, sustainable and modern energy for all" through a combination of national action and international cooperation. The large financial commitments made by the international community as part of the Paris Agreement require practical implementation tools in order to deliver results. We are in close discussions with African organizations that have been accredited by the Green Climate Fund as potential recipients of such funding with a view to channeling such funding through AGC. The AGC concept was presented in collaboration with the AfDB and The Rockefeller Foundation at a side event during COP 22 in Marrakech in November 2016 and was included in the recommendations section of the SEforALL Finance Committee Report which was presented to Africa's Heads of State in Addis Ababa on 13th July 2015 at the Financing for Development Conference.



AGC is aligned with NEPAD's vision for regional integration in the energy sector and can facilitate the harmonisation of regional and national policies on energy infrastructure and power trade.



AGC is designed as an implementation tool for the AfDB's New Deal on Energy for Africa and addresses the following strategic themes of the New Deal:

- ① **enabling utility companies for success** - through its role as an intermediary offtaker, AGC will support the successful development of utility companies in the following ways:
 - ▶ Improve volume and reliability of power supply by facilitating substantial additional capacity ;
 - ▶ Reducing transaction time and cost and ensuring fair risk allocation under standard form documentation;
 - ▶ Acting as a skilled negotiator vis-à-vis the IPPs and lenders;
 - ▶ Reducing contingent liabilities associated with termination payments by reducing the quantum of termination payments;
 - ▶ Releasing resources to focus on structural reforms and the transition to cost-reflective tariffs;
 - ▶ Reducing dependence on high cost, carbon intensive emergency power;
 - ▶ Facilitating power trade to promote efficient use of regional resources and to maximise utilisation of power assets; and
 - ▶ Through increased trade, strengthening the business case and bankability of additional transmission infrastructure.

- ⑤ **dramatically increasing the number of bankable energy projects** – by acting as a creditworthy counterparty, AGC reduces the credit risk for investors in IPPs, mitigates transaction risk and improves financing terms, resulting in many more bankable projects.
- ⑥ **increasing the funding pool to deliver new projects** – the reduced risk profile at IPP level through the introduction of AGC will make the sector attractive to a wider pool of investors as well as:
 - ▶ Reducing the cost of capital at IPP level;
 - ▶ Reducing the risk profile of the wider power sector through increased trading opportunities;
 - ▶ Increasing the tenor (8-15 years) and reducing pricing (up to 300bps) of project finance debt;
 - ▶ Creating a route to market for smaller projects through aggregation;
 - ▶ Making the operating environment more supportive for private sector project developers and investors;
 - ▶ Increasing the potential for refinancing, enabling development capital to be recycled into new projects; and
 - ▶ Facilitating involvement by lower risk investors, including local institutional investors, thereby enabling the introduction of local currency tranches of PPAs.
- ⑦ **accelerating major regional projects and driving integration** – the AGC model is ideally suited to major regional projects. By acting as a single contractual counterparty for IPPs, Africa GreenCo will dramatically reduce transaction time and cost. By trading across its portfolio of IPPs and offtakers, AGC will help liquefy regional power markets and support structural reform of the power sector.



The Africa Renewable Energy Initiative (AREI) is an inclusive, transformative, Africa-owned and Africa-led effort to accelerate and scale up the harnessing of the continent's huge renewable energy potential. Under the mandate of the African Union and endorsed by the Committee of African Heads of State and Government on Climate Change (CAHOSCC), the Initiative is set to achieve at least 10 GW of new and additional renewable energy generation capacity by 2020, and at least 300 GW by 2030. By fostering partnerships and bringing together existing initiatives while mobilizing new international support for a secure and people-oriented energy system, the African Renewable Energy Initiative will help African countries gain access to cleaner energy that drives their development and prosperity. AGC aims to be part of the solution.

AGC objectives are fully aligned with AREI's two over-arching goals:

1. to help achieve sustainable development, enhanced well-being, and sound economic development by ensuring universal access to sufficient amounts of clean, appropriate and affordable energy; and
2. to help African countries leapfrog towards renewable energy systems that support their low-carbon development strategies while enhancing economic and energy security.

In reaching these goals, AREI will adhere to five key principles including:

- ⑤ contributing to achieving sustainable development in Africa by scaling up and accelerating the deployment and funding of renewable energy in Africa; and
- ⑥ boosting intra-regional and international cooperation and promoting and supporting only those activities and projects that are agreed by all countries concerned and impacted.

AGC shares AREI's recognition that all potential source of capital need to be harnessed in order to realize Africa's renewable energy potential. We believe that AGC's proposed intervention represents an efficient means of helping to achieve AREI's goals by providing a sustainable and scalable structure within which the available concessional capital can be leveraged to unlock large amounts of private sector capital from a much broader range of investors and at significantly lower cost. AREI supports transformative, programmatic approaches such as AGC and advocates country ownership, in line with AGC's focus on establishing an African-owned and African-led vehicle.

1.2 Alignment with other relevant initiatives and organisations

It is important to ensure that AGC's proposed role is not already being adequately fulfilled by an existing initiative and/or an existing organisation. We have therefore undertaken a detailed analysis of the various organisations and initiatives that are currently active in the market. The primary conclusion from this analysis is that AGC is additional, and complementary to, the vast majority of such existing structures and endeavours. Please refer to *Annex 2 (Africa GreenCo Additionality and Complementarity Table)*.

2

Precedent for Power Sector Intermediary – PTC India

AGC aims to emulate the success of comparable independent power offtakers in developing markets. These pioneering interventions have demonstrated the financial feasibility and potential impact of an aggregator and trading intermediary on local power markets.

The most applicable case study to the AGC model is PTC India Limited (PTC), formerly known as Power Trading Corporation of India Ltd. PTC was established, under the directions of the Government of India, as a non-government company to facilitate multi-state power projects and trade power and has been operating in this role for 17 years.

The evolution of the Indian power market up to PTC's creation closely mirrors that of African power markets. India had five regional grids each governed by a Regional Electricity Board (REB), comprising of the Heads of the member State Electricity Boards (SEBs) that acted as each state's public sector power utility. These regional areas were only minimally interconnected. During the 1990s, the power sector was unbundled to allow privately financed and operated IPPs to support the growing demand for power. IPPs contracted directly with SEBs, with a guarantee by the State Government and in some cases counter-guarantees by the Central Government. Investment decisions in power generation and transmission infrastructure were uncoordinated and inefficient: there was limited inter-state and almost no inter-region power trading.

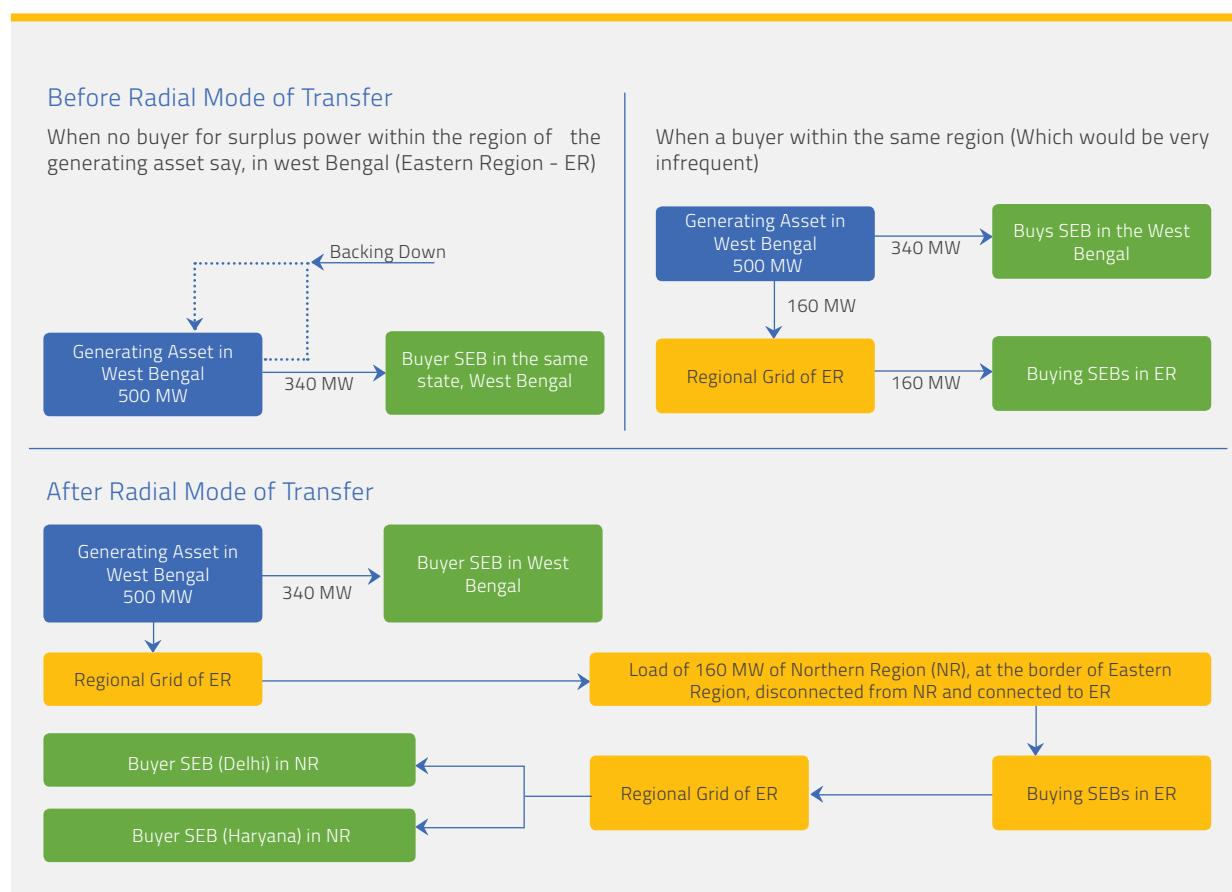
PTC was developed in response to the Government's decreasing appetite and capacity to sign sovereign and state-level guarantees for IPPs and a recognition that there was scope for more efficient power trading. PTC was founded as a private company in 1999 by the Government of India and majority-owned by three state-owned enterprises (SOEs): the National Thermal Power Corporation (NTPC), Powergrid Corporation of India (POWERGRID) and Power Finance Corporation (PFC).

PTC's operating model had two core components:

- 1 Trading power from regions/utilities with a surplus to regions/utilities with a power deficit on a short term basis. PTC pioneered the Indian market for differentiated peak and off-peak power trading and introduced the Day Ahead Market. In addition to utilities, PTC works with more than 400 industrial/bulk consumers directly.
- 2 Acting as an intermediary PPA offtaker for IPPs creating transparent and standardized negotiation and contracting practices and selling power to SEBs under PSAs. PTC directly addressed IPP concerns about creditworthiness by limiting exposure to specific utilities and payment securities and through its ability to divert power to alternative buyers in case of default. PTC's risks were to be mitigated by a planned deduction from Central to State government grants.

Initially, PTC's status as a creditworthy long term PPA counterparty was limited; the planned government support failed to translate into a concrete agreement and no private finance was willing to guarantee the risk or invest in PTC. As a result, the team behind PTC focused on short term trading. For its earliest transactions, PTC worked with 10-15 agencies (the generating companies, utilities and grid operators) to evacuate surplus power across two regions. This initial transaction structure entailed shifting the supply of part of the Northern REB around Varanasi to the Eastern REB, which was connected to the generation asset in West Bengal. The resulting excess power in the Northern REB was then supplied to SEBs in Haryana State and Delhi. Under this arrangement, PTC generated INR4.25bn (USD63m) sales on the basis of its INR60m (USD0.9m) paid in capital and without any working capital or other debt.

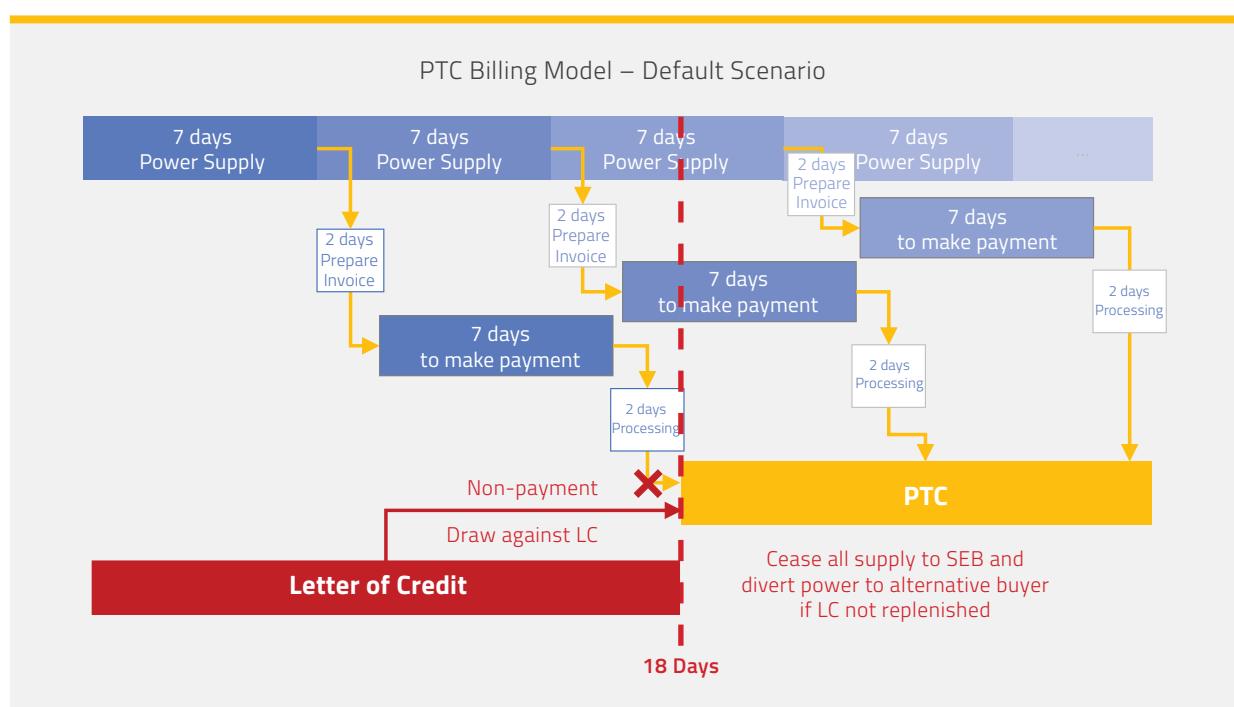
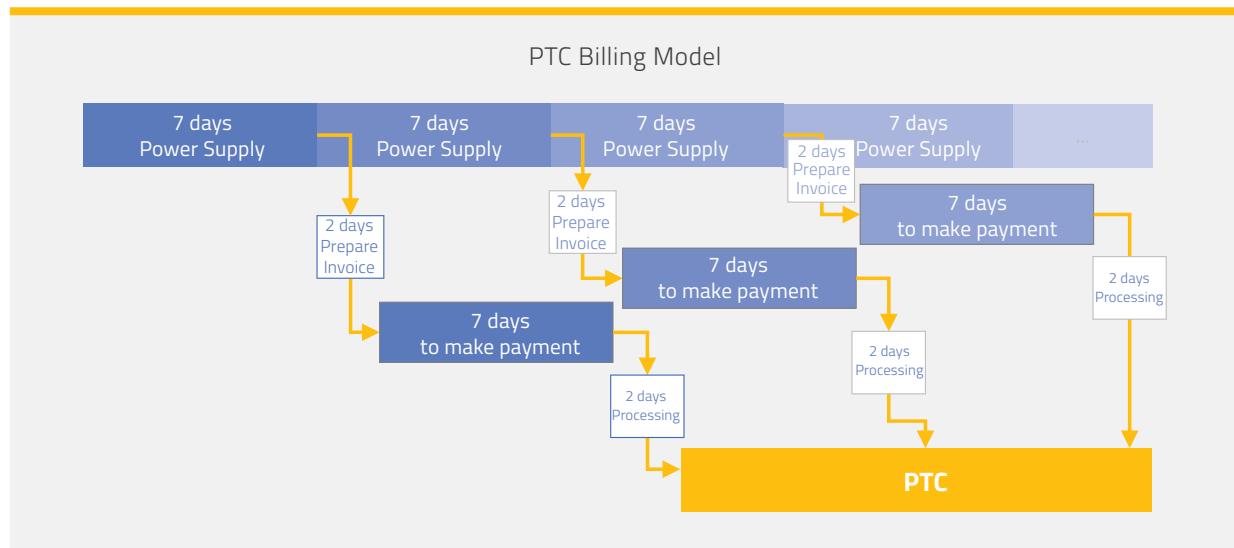
An illustration of this trading arrangement is set out below.



This technical model for delivery established the viability of PTC's intermediary role. A standard transaction structure emerged that limited PTC's financial risk with the following key features:

- ▶ PTC billed the SEBs on a weekly basis for the cost of power plus INR 0.05 (USD 0.0007)/kWh margin;
- ▶ The delivery point for the power was set as the intersection of the supplier SEB and buyer SEB – wheeling charges and transmission losses were charged to the supplier and buyer at the regulated rate;
- ▶ Buyers were given one week to make payment, plus 4 days for invoicing and transaction processing;
- ▶ If payment was not made after 18 days, PTC drew on an 18 day letter of credit established by the buyer SEB with a local financial institution;
- ▶ If the LC was not then replenished, PTC would no longer supply power to the buyer SEB;
- ▶ If an alternative buyer could be found, PTC would divert the power to this offtaker on a short term basis;
- ▶ If an alternative buyer could not be found, PTC would not purchase power from the supplier; however, the capacity payment under the PPA was on a take-or-pay basis;
- ▶ The buyer SEB would be liable to pay the capacity payment to the supplier SEB; this amount could be reduced by any excess revenue generated from the diversion of power to an alternative buyer;
- ▶ The PPA billing cycle was consistent with the PSA billing cycle of 18 days giving PTC time to receive payment before paying – so PTC had minimal working capital requirements;
- ▶ Suppliers/Buyers would directly settle transmission/wheeling charges with POWERGRID/SEB.

The supplier billing model in normal and default scenarios is illustrated below.



As PTC grew with this short term radial mode trading model and transaction structure, it also sought to establish itself as a creditworthy offtaker for longer term power purchases. PTC management believed that the following conditions needed to be satisfied in order to be seen to be creditworthy:

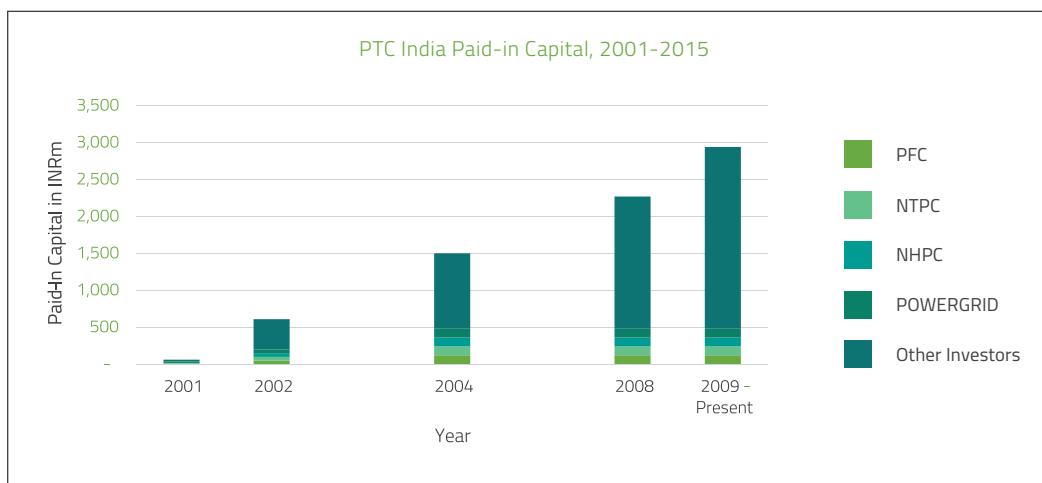
1. It must have sufficient net worth to collateralise larger PPA obligations;
2. It must have a higher profile in the market;
3. Investors must understand and accept PTC's capacity to trade in case of default; and
4. It had to ensure timely payment by the offtaker/buyer SEB under the PSA.

In terms of proving the ability to trade in case of default, PTC felt comfortable that the introduction of trading as a licensed activity in the 2003 Electricity Act, and POWERGRID's renewed investment in regional interconnections, demonstrated PTC's viability and ratified its role in the market.

In terms of timely payment, PTC planned to transfer its weekly billing model and 18 day payment cycle established in the short term trading activities above. In addition, PTC decided to set an internal requirement of at least two offtaker PSAs for any PPA with installed capacity greater than 300MW. This last condition was introduced to increase PTC's confidence of sale in case of default on one of the PSAs – the tariffs and transaction structure would act as a pre-agreed framework for diverting power to the other offtaker.

Capitalisation was the key limitation. PTC approached its existing shareholders to allow management to raise INR7.5bn (USD112m) authorised capital. Two additional investors joined the shareholder (Tata Power and Damodar Valley Corporation – a regional SOE), but the total additional capital raised fell well below the target. Therefore PTC sought to launch an Initial Public Offering (IPO) to engage a wider set of investors and raise PTC's profile. Despite having only 3 years' track record and the perception that the power sector was too high risk, PTC was able to use the IPO to more than double its paid in capital base from INR608m (USD9m) to INR1,500m (USD22m), and had an additional UNR322m (USD5m) share premium. To support subsequent growth, PTC India has had two Qualified Institutional Placement rounds in 2008 and 2009. As of 2015, paid-in capital is just under INR3bn (USD45m) and total net worth is INR24bn (USD357m).

The basic evolution of the capital structure over time is as follows:

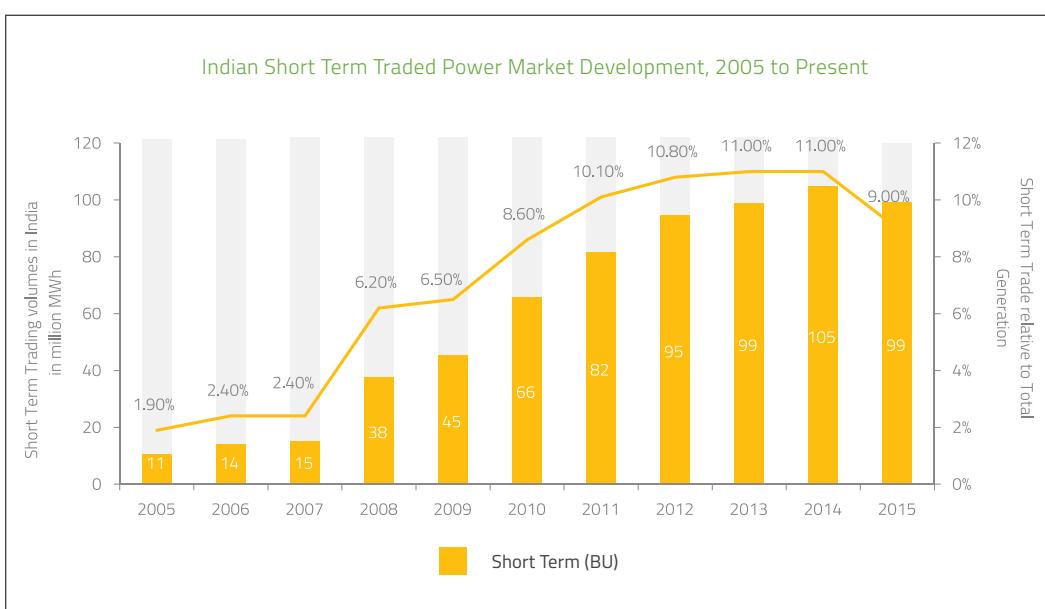
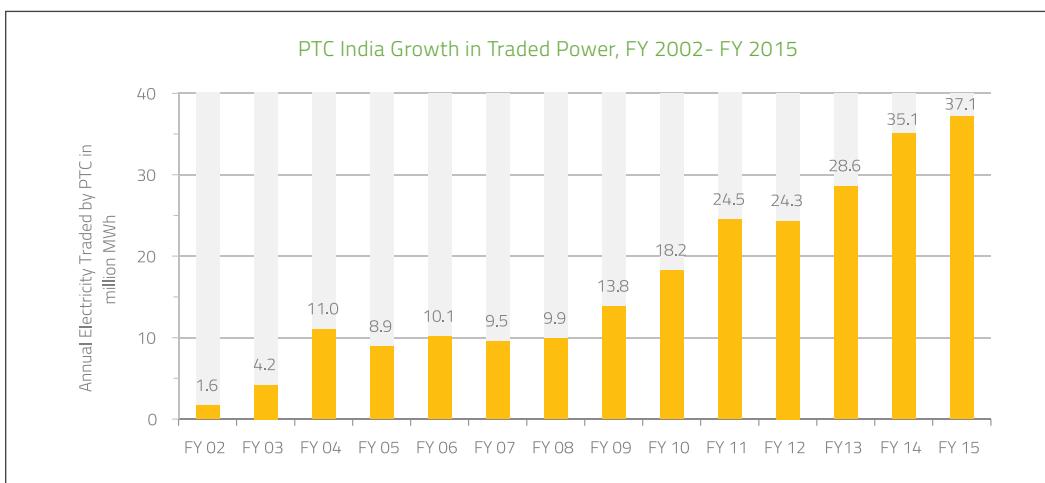


Using this capital base, PTC India has been able to act as a creditworthy PPA counterparty for 7,000MW of installed capacity from a pipeline of 14,000MW. This has unlocked well over USD5bn of private investment even on a conservative estimate of capital costs for new IPPs. As planned, PTC's involvement as an offtaker since 2004 has resulted in a shift away from government guarantees.

In addition to operating at the SEB/REB level in India, PTC has also developed short term cross border trading and long term power purchase and sale activities in South Asia, working with Nepal, Bhutan and Bangladesh. In 2015, PTC traded 6.75 TWh on a short term basis and has a PPA contract for 118MW installed capacity in Bhutan and a long term sale agreement for 250MW equivalent to Bangladesh.

PTC's role in developing the Indian and regional cross-border power markets has been an unqualified success. As a trader:

- ▶ PTC has helped grow overall traded volumes from 1.6 TWh in 2001 to 37 TWh in 2015;
- ▶ PTC has a 30-40% market share;
- ▶ Total short term traded volumes have increased from 2% of total generation to approximately 10% from 2005 to 2015;
- ▶ PTC demonstrated the viability of cross-border power trading;
- ▶ PTC increased investor confidence in supporting IPPs;
- ▶ Suppliers' fixed costs per unit of power fell as capacity utilisation increased;
- ▶ Supplier/power plant revenues increased as they were able to maximise capacity utilisation;
- ▶ Areas of power deficit moved closer to supply/demand equilibrium.



As the market developed, PTC took on a number of additional roles in the market, including:

- ▶ Supporting IPPs with direct equity and debt investments through PTC India Financial Services (PFS) a joint venture with Goldman Sachs and Macquarie;
- ▶ Taking an intermediary position on fuel supply contracts for coal power plants – where PTC procured fuel in return for power output;
- ▶ Creating a retail utility to sell power directly to private consumers with a demand >1MW installed capacity equivalent;
- ▶ Co-sponsoring India's first power exchange (IEX) which now has a 90% market share of exchange-traded power.

PTC acts as an indicator of the potential impact and financial feasibility of an intermediary model; for AGC the key questions are then how this model can be adapted to fit African power markets. While the Indian and African contexts are clearly different, and operating across multiple countries presents additional challenges when compared to operating within a single country, PTC's management offered the following insights into the similarities between the market contexts in India and Africa:

- ◉ Fragmented State (India) and National (Africa) utilities and transmission infrastructure;
- ◉ Growing collaboration and coordination across regional power pools (5 in India, 4 in sub-Saharan Africa);
- ◉ Low average creditworthiness of offtaker utilities;

- ④ Desire to eliminate sovereign guarantees for PPAs;
- ④ High growth in / latent demand for power;
- ④ Focus on renewable energy versus fossil fuels;
- ④ Substantial political and technical coordination will be required to implement a new aggregator or trading model at scale.

PTC India therefore provides a concrete example of the significant role an intermediary offtaker and power trader can play in increasing power generation and trade and stimulating the power market. The backdrop differs in a number of important ways, including:

- ④ Africa has no single overarching federal government to drive AGC's development, but this role could be fulfilled to some extent by pan-African bodies such as the AfDB and the AU and regional bodies such as the Regional Economic Communities and regional power pools;
- ④ The large surpluses identified in India are not currently present in Africa, restricting AGC's ability to trade significant volumes and build its capital base as rapidly as PTC, although some surpluses are expected to occur in the short-to-medium term.

AGC intends to focus on its core role as an intermediary offtaker and power trader rather than diversifying into the additional roles PTC undertook, but will also respond to market conditions as they evolve. As noted above, ultimately, once Africa's power sector is strengthened, its utilities achieve creditworthiness and it has a liquid electricity market, AGC's role as an intermediary offtaker will become redundant and AGC will follow in PTC India's tracks, becoming one of a number of traders in the power markets it will have helped to develop.

The ultimate conclusion of Tantra Thakur, the former Chairman and Managing Director of PTC India, was that:

“ Establishing an aggregator who not just plays an interface with utilities, IPPs, industrial buyers and integrated transmission companies but also works through credit enhancement methodologies, will provide a high level of comfort to investors and lenders both. In any of the cases, this entity can be used as an interface with existing and functional pools to help spread their depth and operational performance. ”

3

Contextualising Africa GreenCo

According to most market participants in a recent ICA Survey, the single greatest hurdle to scaling up private sector investment in energy projects is the lack of creditworthy offtakers. This section describes:

- ⌚ how offtaker creditworthiness is incorporated into project finance credit evaluations;
- ⌚ how utilities are themselves evaluated;
- ⌚ the principal creditworthiness indicators of African utilities; and
- ⌚ credit enhancement strategies relating to offtaker risk,

and in each case describes the role AGC can play.

3.1. Assessing Offtaker Creditworthiness

While Offtaker creditworthiness is a crucial factor when deciding whether to invest in a project, it is not generally easy for a potential investor to access sufficient information to enable it to make its own credit assessment, and some investors do not have the expertise to make such assessments themselves. Some power projects seeking commercial capital or commercial investors looking to invest in IPPs may therefore collaborate with rating agencies to provide a transparent, consistent understanding of a projects' risk profile. The methodology used by ratings agencies for project finance reflects the typical investor approach to risk analysis and is a helpful guide for where offtaker risk sits in the decision making process.

Projects are typically evaluated across a number of parameters, including:

Table 1: Project Finance Risk Assessment

Parameter	Issues	AGC Impact
Construction	<p>Project Complexity: in terms of technology, local geography and community engagement.</p> <p>EPC Contract: capacity and reputation of the EPC contractor and availability of alternative contractors.</p> <p>Liquidity: ability to meet capital expenditure requirements and any debt obligations during the construction period, including reserves and/or guarantees in respect of cost and time overruns.</p>	
Operations	<p>Revenue risks: credit strength of offtaker and capacity to honour PPA commitments, tariff levels relative to costs and currency issues.</p> <p>O&M risks: issues relating to the availability of operating expertise, ongoing sponsor engagement, maintenance schedule and costs.</p> <p>Availability: plant output estimates of the specific technology and network interconnection and availability such that all power produced can be evacuated into the network for sale</p> <p>Exposure to fuel supply or underlying resource availability and price risk to ensure minimum production targets and ongoing revenue generation.</p> <p>Competitiveness: relative to other generating assets, does the project reflect competitive cost of installation and operation. How effectively could the project sell to another buyer in case of contract default.</p>	<p>Yes – improved offtaker creditworthiness</p> <p>Yes – improved despatch thanks to AGC being a power trader</p> <p>Yes – increase market access in default scenario</p>

Financial Structure	Debt structure of the SPV: level of Debt Service Coverage Ratio and covenants, inflation protection, tenor of debt relative to contract date, refinancing parameters.	Yes – longer tenor, lower cost debt → higher DSCR
	Reserves: 6m debt service as a benchmark reserve, with higher levels for projects with more variable output; maintenance reserve.	
	Insurance: coverage of policy and strength of insurance provider(s) and guarantors of the projects.	Yes – access point for insurance/ Guarantee products
	Convertibility: reliable sources of hard currency in order to make payments in USD (or local currency equivalent of USD) and exemption from (or absence of) capital controls to return profits and capital to international investors.	Yes -USD balance sheet
	Currency Risk: relative volatility of local currency and party responsible for managing any foreign exchange exposure from payments made in local currency.	Possibly – see <i>Section 5 (Financial Viability)</i>
	Termination: clear line of sight on source of potential termination payment either from the counterparty balance sheet or through security arrangements.	Yes – AGC capitalised to make termination payment
Legal Structure	Counterparty: the relative creditworthiness of the SPV's bank, LC provider, swap counterparty and other financial counterparties.	Yes , AGC will attract better rated banks for these roles
	Relationship with parent of developer in terms of bankruptcy and independence of decision making and management.	
	Experience of sponsor: developer and other sponsors' operational experience and ability to deliver on the shareholders' expectations.	
	Certification of Occupancy: right of developer and sponsors to access and operate the plant at the expected location.	
	Security structure in terms of seniority of debt/equity holders and step-in rights in case of bankruptcy.	

Utilities across sub-Saharan Africa are generally viewed as high credit risk. In terms of formal rating, only Eskom and NamPower have entered public capital markets transactions to raise capital: Eskom, whose rating was downgraded in 2016 to Ba1 Negative (Moody's), BB Negative (Standard & Poors) and BBB- Negative (Fitch); and NamPower whose rating is BBB- Stable (Fitch).

In Africa, public entities tend to face various challenges that influence credit risk analysis. Feedback on key utility creditworthiness issues from ratings agencies active in the African public sector market are described below and in more detail in *Annex 7 (Utility Creditworthiness Factors and Credit Rating Methodologies)*.

Revenues	Many African utilities are constrained in their ability to increase end user tariffs, whether through affordability or political imperative. If utilities were able to set cost-reflective tariffs, increase collection efficiency and reduce distribution losses, analysts estimate that they could capture up to 50% additional turnover. ⁸
Expenditure	Most utilities have a high proportion of non-discretionary expenditure (such as employment costs), leaving minimal scope for capital expenditure and maintenance, reducing operating efficiency and creating substantial supply deficits.
Credit Protection Ratios	Utilities tend to have a combination of high gearing, low interest cover, minimal liquidity and insufficient internally generated cash flows (see above). As a consequence, they have limited/no capacity to access commercial finance.
Government support	Given the low revenues and minimal flexibility around expenditure, most utilities are dependent on some form of governmental budgetary support. However, given the wider fiscal environment, utilities have limited access to predictable commitments. Even when funds are approved, the process for transferring capital from central governments to utilities is often cumbersome, bureaucratic and time consuming – meaning that many utilities have to tap (financially or strategically) expensive emergency sources of funding – often reallocating funds from longer term strategic spending priorities – to cover short term liquidity needs.
Technical Efficiency	African utilities have high transmission losses and outages. All of the utilities who report to the World Bank report losses in excess of 5% and some countries – including Togo, the Republic of Congo and Niger – report losses of over 30%. For IPPs, these losses are theoretically paid for by the offtaker provided they occur beyond the delivery point; in practice, if utilities are incurring high losses but paying for them, their ultimate financial health will deteriorate and with it, the credit risk.
Budgeting	Accurate budgeting forecasts are limited: instead, most utilities have more of a wish list of investment projects that does not directly relate to how budgets are actually spent, and where there is a budgeting plan, the full value of the investment required is frequently significantly underestimated.

⁸Eberhard et.al, Africa's Power Infrastructure , World Bank 2011 p134 referencing Briceno-Garmendia and Shkaratan, Power tariffs :caught between cost recovery and affordability, World Bank 2011

Billing and collection	While many utilities are improving their collection rates through technology, most sub-Saharan African utilities have large numbers of outstanding payments and massive arrears. Across the SAPP, only one utility, Eskom, has a consistent average accounts receivable turnover of less than 30 days; for utilities in Zambia, Zimbabwe, Tanzania and DRC, debts are on average unpaid for over 100 days.
Staff costs	The relative ratio of expenditure allocated to staff is typically very high – see non-discretionary spending above. Salary requirements and management inefficiency mean that utilities cannot be flexible and reactive to market dynamics.

3.2. Implications

There are two main consequences of this high actual and perceived credit risk:

- ① Lenders and investors require higher returns over a shorter period of time to recoup investment; and
- ② Lenders and investors require credit enhancement to backstop PPA obligations and improve the risk profile of the transaction.

Both of these consequences reduce the universe of bankable projects. First, IPPs are not bankable because they cannot generate the equity return and debt service thresholds imposed through a higher cost of capital. Second, as a result, the tariffs required to make projects financially viable for investment are too high for utilities, which are already struggling to balance a push for cost-reflective tariffs with providing power to a small, low-income consumer base. Lastly, credit enhancement adds a layer of cost – concessional or otherwise – and is currently in limited supply.

3.3. Credit Enhancement

Against this backdrop it is unrealistic to expect the private sector to make investments at the scale needed to bridge the current funding gap.

Because of concerns regarding the financial health of offtakers, the last 20 years have been dominated by hard currency PPAs bolstered by credit enhancement for investors seeking to safeguard payment streams.

For IPPs in Africa the main credit enhancement strategies employed by investors, in addition to the requirement for offtakers to provide liquidity support, are:

- ① Raising **debt and equity from DFIs** in order to benefit from the halo effect – since a default against these DFIs may cross-default ODA and concessional finance extended by such DFIs to other projects. However, given the c.\$490 billion of new investment in generating capacity required, it is not sustainable for investors to rely on DFI funding;
- ② Seeking a **letter of comfort/support** from the local Government in which it acknowledges the utility default risk and makes a commitment to ensure payment. The letter of support issued by the Government of Kenya in relation to the USD 15bn Kinangop wind farm is currently the subject of arbitration before the International Chamber of Commerce and will provide a useful data point as to the protection afforded by such undertakings;
- ③ Giving **PPA payments seniority/preferred status in domestic legislation;**
- ④ Obtaining **3rd party guarantees or insurance from MDBs**, DFIs or private sector against payment default under the PPA and/or Implementation Agreement. Principal providers of such insurance include MIGA, OPIC and ATI, and such third party guarantees are mainly issued by the World Bank Group, AfDB and other bilateral and multilateral DFIs. Negotiating such instruments can however take a long time and involve significant cost and calling on such instruments may also be a difficult decision bearing in mind the consequential impact this may have on other funding lines provided to the defaulting state and the detrimental impact this would have on the beneficiary's future business in the region; and
- ⑤ Seeking a **direct contractual obligation or guarantee** from the host government to cover both PPA payments and potential termination payments.

A summary of the key features and uses of the various credit enhancement strategies listed above is included at *Annex 6 (IPP Credit Enhancement Strategies)*:

AGC aims to work within this credit enhancement context by:

- ⑤ Reducing the likelihood of PPA termination through its portfolio approach and ability to trade power;
- ⑤ Acting as a conduit for additional portfolio level political risk/offtaker risk insurance or guarantee protection; and
- ⑤ Creating additional disincentives for utility default through including African sovereigns in AGC's shareholder base, alongside key DFIs and donors.⁹

While AGC recognises the tremendous role that guarantees and insurance have played in improving the bankability of projects, ultimately AGC hopes to reduce the need for the private sector to rely directly on these credit enhancement instruments. There is however scope for AGC to:

- a. act as an aggregator or entry point for guarantors and insurers to work directly with IPPs and offtakers on AGC pipeline projects, and
- b. explore the possibility of insuring or guaranteeing its own exposure to offtaker and government default across its portfolio on a diversified basis in order to protect AGC's capital base.

3.4. Sustainability of Current Approach

The current project-by-project approach to supporting grid connected renewable energy IPPs in sub-Saharan Africa is unsustainable. Significant weaknesses of the current model include:

- ⑤ If an offtaker default leads to PPA termination, a single Generator does not have the contractual, regulatory or operational ability to 'trade out of' the position of losing its sole customer. In this eventuality, there is no expected alternative other than for the Generator to exercise the early termination buy-out provisions included in the transaction documents; i.e., to crystalise the host Government's contingent obligation to purchase the generation facility.
- ⑤ There is a limit to the fiscal burden which host Governments can prudently incur under early termination buy-out provisions. In various SSA countries, significant project delays (and associated project development costs) are already witnessed due to host Governments resisting additional fiscal burden. The current bilateral IPP model provides no solution to this.
- ⑤ Credit enhancement provided on a project-by-project basis typically adds significant cost and equally significant delays to transaction execution.
- ⑤ To the extent that DFIs take sovereign credit risk on their own exposures, they effectively create a 'closed shop' with each DFI financier accepting sovereign credit risk only in relation to debt or equity which it has provided. Although stand-alone credit support instruments are available, this bundling of finance with the acceptance of sovereign credit risk by DFIs puts private sector financiers at a significant disadvantage.
- ⑤ Even with multiple layers of DFI support and relatively high tariffs, renewable energy projects in SSA (outside of South Africa) are still not particularly attractive to private sector sources of capital. Project development times are often very long; fully at risk development costs incurred prior to financial close are usually very high; the risk of not reaching financial close is often very real and in any case much higher than it needs to be; project documentation and structures are cumbersome; and the prospect of making a claim against a host Government, with or without sovereign credit support, is a daunting one. This all leads to a market which is effectively inaccessible to all but a fairly small group of well-funded, sophisticated market participants, most of whom are either DFIs or are funded directly or indirectly by DFIs.
- ⑤ Although there have been notable attempts to standardize project documentation, e.g. via South African REIPPPP, Scaling Solar, GET FiT Uganda and now GET FiT Zambia, the predominant model is of bespoke negotiation of project agreements on a project-by-project basis. Lessons learnt are not sufficiently crystalized into accepted principles and practices, and there is an unacceptable degree of 'reinvention of the wheel' on successive projects, as well as on similar projects in different countries. In some markets (particularly in relation to some REFIT programs in the region) the standardized documentation proposed is very clearly unbankable under conventional project finance principles.

⁹Please refer to *Section 7 (Contracting Strategy, Risk Allocation and Procurement)* and *Section 8 (Corporate Structure, Governance and Risk Management)* below.

3.5. Contingent Liabilities and Debt Sustainability

The IMF is advocating the incorporation of contingent liabilities in a more consistent and structured way into debt sustainability analysis and has been researching the impact of contingent liabilities on governments to attempt to quantify the dangers of over-extension in terms of explicit and implicit support to SOEs and strategic markets.

The IMF's ability to record all sovereign guarantees in its presentation of Public Sector Debt Statistics depends on the sovereigns reporting all such guarantees. Contingent liabilities against contractual obligations are not consistently or uniformly reported. While in theory governments should provide a breakdown of contingent liabilities under the IMF's Fiscal Transparency Code, in practice, it is mainly only advanced economies that do so.

There are a number of factors that are driving the current discussion around debt sustainability and contingent liability accounting:

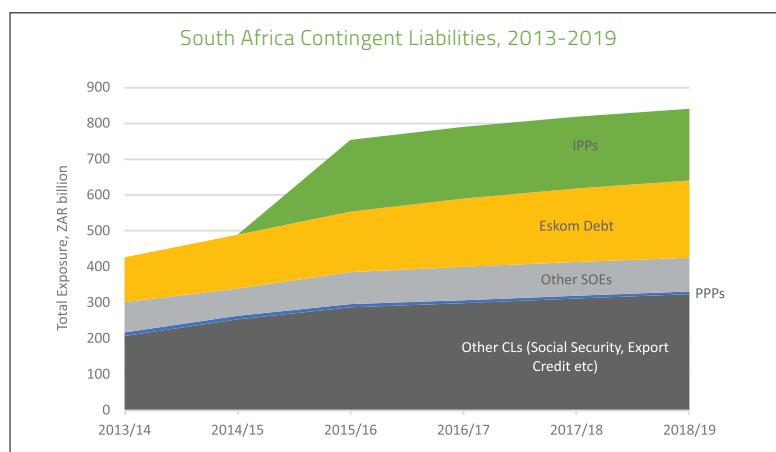
1. Under cash accounting no expense is recognised until it occurs – the contingent liabilities do not feature. Under accrual accounting practices, if the probability of paying out is greater than 50% and the quantum of payments can be estimated, the government must record a provision against these commitments. If the probability is less than 50% or the estimates of payments are unclear, the contingent liabilities are not recognized until the discrete trigger events occur. In the case of sovereign guarantees, the probability of default can reasonably be assumed to be below 50% - so they are not recognised even in the stricter accrual accounting methodology;
2. Governments, particularly in Africa, may not have or may not choose to report the available data to accurately describe the current level of contingent liabilities;
3. Where a contingent liability is backed by an asset (e.g. a power plant) that would transfer to the government in case of default (i.e. where termination triggers a 'put and call' option), the typical approach is to consider the liability net of the estimated value of the asset;
4. Perversely, there is a disincentive to disclose government contingent liabilities: recording these liabilities may lead investors to believe that an implicit guarantee is in fact a strong commitment, and may also put that country at a disadvantage relative to its peers in that it may be harder to attract international financing versus another country that does not report contingent liabilities.

However, the evidence on the ground is that countries are becoming increasingly transparent about their contingent liabilities, providing supplementary information in budget documents, fiscal reports and financial statements.

Under South Africa's REIPPP program, the South African government provided sovereign guarantees to all PPAs signed with the selected renewable energy projects. While these were not immediately recognized as liabilities, in 2015/6, the South African Treasury updated its reporting framework on contingent liabilities in line with international best practice. This resulted in the addition of ZAR200bn (USD13bn) additional liabilities representing Eskom's 20 year PPA obligations – essentially an overnight increase of 36%. Given South Africa's debt sustainability and sovereign credit rating concerns, future IPPs are not forecast to benefit from sovereign guarantees nor would it be fiscally prudent for the country to continue providing these.

In Kenya's Medium Term Debt Strategy, each PPP contract obligation is described in Appendix 2 of the document to allow analysts and investors to incorporate the figures into their calculations.

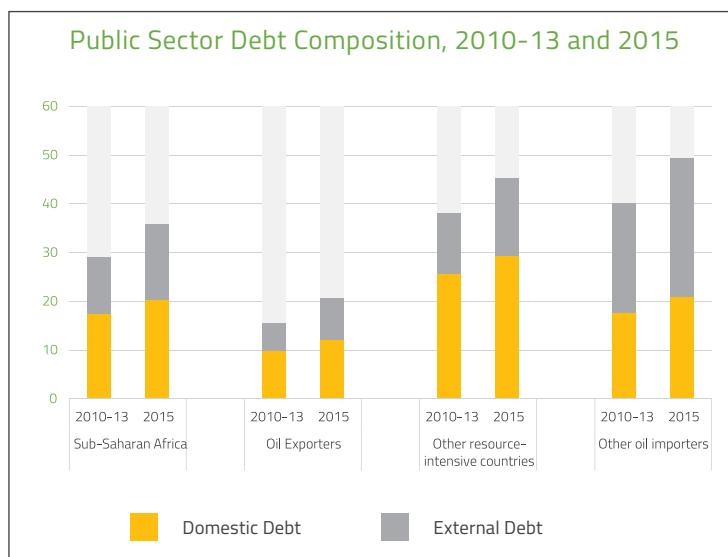
The trend – which may well become an IMF requirement – of increasing transparency around contingent liabilities disincentivises governments to provide guarantees. This is because:



- ④ International organisations – MDBs, donors and governance entities like the OECD and IMF are prioritizing efficient fiscal management in developing countries to encourage budget surpluses and prudent medium term spending and borrowing strategies. Overdependence on contingent liabilities is one major indicator of inefficient fiscal management.
- ④ External lenders – public and private – will incorporate the quantum of guarantees into their credit analysis; countries with more sovereign guarantees are likely to bear a higher cost of capital than those with fewer guarantees.
- ④ Contingent liabilities have been demonstrated to bring with them adverse implications in terms of macro-economic risk – as a consequence of the global financial crisis and increasing recognition of role that unreported/anticipated exposure created in exacerbating the impact of a shock.
- ④ IMF forecasts on debt sustainability are becoming better able to model how contingent liabilities relate to debt sustainability thresholds. A country with more guarantees will be more likely to break a key threshold and therefore the IMF will limit its capacity to borrow for other activities.
- ④ Investors and analysts are also better aware of the correlation between guarantee exposures – in that obligations under a series of PPA guarantees are more likely to be called at the same time, creating a system failure.

The IMF's Debt Sustainability Assessment and Debt Sustainability Framework set out the parameters for how governments should target different thresholds/benchmarks for public debt. For a summary of these frameworks and their application to countries in sub-Saharan Africa please refer to *Annex 5 (Application of IMF Debt Sustainability Assessment and Debt Sustainability Framework in Africa)*.

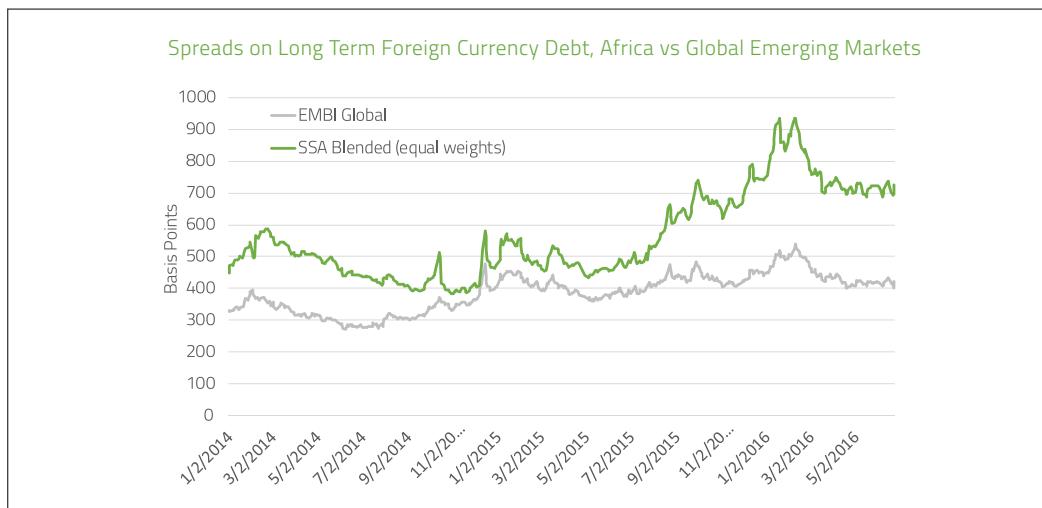
With this higher base level of external debt, a gloomy macroeconomic outlook and a shift of capital out of emerging markets, tapping international capital markets may not be straightforward in the near term for most African countries. The external financing environment has now tightened, with the increase in financing costs for sub-Saharan African borrowers being much more pronounced than for most emerging markets.



From an African government's perspective, reducing infrastructure dependence on sovereign guarantees is more important now than ever before: as market growth stalls, the impact of a shock will be more pronounced. According to the recent IMF publication on the Regional Economic Outlook for Sub-Saharan Africa published in April 2016:

“ economic activity in sub-Saharan Africa has weakened markedly ... the growth for the region as a whole fell to 3½ percent in 2015, the lowest level in some 15 years, and is set to decelerate further this year to 3 percent—well below the 5 to 7 percent range experienced over the past decade. ”

As the IMF remarked, in a less forgiving financing market the reality is that fiscal policy will also need to be recalibrated among the region's market access countries where fiscal and current account deficits have been elevated over the last few years, lest they find themselves with low buffers and vulnerable to a financial crisis if external conditions worsen further. At the same time both external and domestic debt contributed to the increase in public debt, and debt sustainability assessments have deteriorated for most countries in the sub-Saharan Africa. Looking ahead, with the external environment projected to remain unfavourable, mobilizing sufficient financing required for power sector projects whilst continuing to require sovereign guarantees with their impact as contingent liabilities on the balance sheets of the governments may become even more challenging. With the external environment now much less supportive, a policy reset is needed to reinvigorate the growth momentum.



We are in detailed discussions with the IMF regarding the impact the introduction of AGC could have in achieving a more efficient management of fiscal risks and reducing the probability of the explicit or implicit contingent liabilities associated with the PPAs entered into by state owned utilities crystallising. The IMF takes a holistic approach, considering the potential fiscal impact of all of the major risks associated with PPA arrangements and the likelihood of them arising. The IMF's preliminary view is that the introduction of AGC as an intermediary offtaker could help to mitigate many of these risks from the public sector perspective.

4

Target Market

AGC represents an ambitious proposal to alter the structure of the power markets in order to stimulate both public and private sector development of renewable energy. Whilst it is conceived as a pan-African concept and would have equal application in each geographical region, it would be highly challenging for AGC to commence operations in multiple regions from the outset. AGC will therefore have to carefully consider the market characteristics within each region in order to determine the most appropriate region in which to embark upon a proof of concept.

This section seeks to analyse and identify the most appropriate markets and projects through which to undertake a proof of the AGC concept, based on AGC's Technical Feasibility Study attached at *Annex 3 (Africa GreenCo Technical Feasibility Report)*.

4.1. Overview of the power pools within sub-Saharan Africa

AGC will not own any generation or transmission assets and will operate within, and seek to develop, the existing power pools. Sub-Saharan Africa has three main regional power markets: the Southern African Power Pool (SAPP), East African Power Pool (EAPP) and West African Power Pool (WAPP). The Central African Power Pool (CAPP) is still in its infancy and has not been considered for the purposes of this Feasibility Study. Currently the power pools are physically separate (and in some instances, not all members within a power pool are interconnected, e.g. Angola in SAPP). However, there are overlapping country memberships in these markets where the opportunity for cross border trade presents itself (Tanzania, DRC), and long term plans for transmission networks to connect the power pools and facilitate trade between them.

The following considerations are key in determining AGC's preferred starting location:

- ① Regional transmission capacity and cross-border trading potential – and thus the physical ability to sell to more than one Offtaker and divert power to alternative purchasers in case of Offtaker default.
- ② The enabling environment for Independent Power Projects and pipeline of projects.
- ③ Local support for regional power market development and role of renewables.

Table 2: Summary of current IPPs in Target African Regions

	East Africa	West Africa	Southern Africa	Southern Africa Ex RSA
Power Pool	EAPP	WAPP	SAPP	SAPP
Data Year	2014/15	2013/14	2014/15	2014/2015
Installed capacity (MW)	53,296	9,912	61,363	14,0
Hydropower Share (%)	20%	34%	21%	78%
Thermal Share (%)	72.4%	66%	62%	22%
Other RE Share (%)	7%	0%	17%	0%
Target RE Share	N/A	N/A	32% (2020) 35% (2030)	N/A
Grid Interconnection ¹⁰	Medium	Low	High	Medium
Trading platform ¹	Medium	Low	High	High
Current IPPs ¹¹	44 / High	24 / Low	74 / High	7 / Low
IPP Environment	High	High	High	Medium
RE Policy Support ¹	High	Medium	High	Medium

¹⁰In the context of sub-Saharan African markets

¹¹Taken from Eberhard, Anton, Katharine Gratwick, Elvira Morella, and Pedro Antmann. 2016. Independent Power Projects in Sub-Saharan Africa: Lessons from 5 Key Countries.

4.2. SAPP Market and AGC SAPP Technical Feasibility Report

AGC can be brought to bear both in East Africa via the EAPP and in West Africa via the WAPP and is keen to continue its discussions with each of these power pools. However, for illustrating the concept, this Feasibility Study focuses on the Southern African Development Community (SADC) as represented through the SAPP. As can be seen from the table above and the Regional Infrastructure Development Master Plan referred to below, the characteristics of the SAPP are most aligned with AGC's priorities: a significant deficit of generation exists in the region, with very little renewable energy other than hydro but its regulatory framework is relatively sophisticated (with daily, hourly and bilateral trading arrangements). SAPP has also witnessed significant recent movement towards more regional integration across the SADC, and particularly with the recent establishment of the SAPP Projects Advisory Unit and RERA's work towards introducing a SADC wide IPP Framework. Please see *Annex 3 (Africa GreenCo Technical Feasibility Report)* for the full technical feasibility study prepared by AGC's Technical Advisors covering AGC's implementation within the SAPP context.

Priorities and initiatives within the Southern African Development Community



SADC Regional Infrastructure Development Master Plan

In the words of Tomáz Augusto Salomão, Executive Secretary of SADC in the foreword to the SADC Regional Infrastructure Development Master Plan (RIDMP): "any meaningful implementation of the RIDMP should accord priority to addressing power shortfalls in the region." The objectives of AGC are therefore entirely aligned to the priorities of RIDMP.



Regional Electricity Regulators Association of Southern Africa

AGC is supported by RERA as it responds to Outcome Statement No. 8 of the SADC Ministerial Workshop on Water and Energy held on 20 June 2016 and to the Market and Investment Framework for SADC Power Projects approved by the SADC Ministers responsible for Energy on 21 June 2016, by addressing some of the risks currently undermining developer and investor/lender confidence in the reliability of IPP's long-term revenue forecasts.

RERA, with the support of the U.S. Department of State, has commissioned Deloitte to develop and implement an IPP Framework within SADC. The framework advocates wide ranging harmonization of national rules and regulations in order to create a level playing field and facilitate cross-border electricity trading with the inherent benefits of cost reduction and regional resource optimization. The ultimate aim is to create a liquid regional power trading market.

AGC will act as a bulk trader within such an environment and assist in the development of the market proposed.

SACREEE

AGC is also fully aligned with the objectives of the SADC Centre for Renewable Energy and Energy Efficiency (SACREEE) as it focuses on offtake from renewable energy IPPs.



Southern African Power Pool

SAPP has established a Project Advisory Unit which is responsible for the preparation and actualization of agreed priority projects. At present, these mainly revolve around transmission lines to connect non-operating members, relieve congestion and evacuate power from new generation projects, all of which are generally more challenging to obtain private sector investment for. SAPP is also driving the regional agenda for universal access and 35% renewable generation penetration by 2030. The AGC model will complement these efforts by facilitating small, medium and large scale investment projects that result in higher availability and security of supply; improving trade liquidity; and more efficient utilization of transmission capacity and interconnection assets.

In addition, SAPP is implementing important regional power trading initiatives, such as a revised methodology for transmission pricing, development of the ancillary services, balancing and financial markets. AGC's creditworthiness and its intermediary offtaker role will facilitate actualization of these regional power market development initiatives.

As set out above, our proposal aligns with the objectives of the SAPP Projects Advisory Unit and RERA's work on the IPP Framework for the SADC region. This proposes an energy trading market structure that is supported by a new legal and regulatory framework, constituting a body of harmonised legal and regulatory rules that will be applicable in each Member State for all cross-border projects. AGC hopes to be able to leverage this groundwork and apply it actively in the market. We believe that through the introduction of a principal intermediary in the market, many of the objectives of the SAPP Projects Advisory Unit and RERA's IPP Framework can be achieved more quickly.

Any structural reform needs to be completed in a context sensitive and politically inclusive manner. In recent decades, and in response to the poor financial and technical performance of their power sectors, developing countries were encouraged to unbundle their electricity utilities, vertically and horizontally, to introduce competition, to create independent regulators, and to make space for private sector participation. However, whilst these developments are generally positive, they do not necessarily correlate with a higher level of private sector investment as IPP investments have arisen in a variety of power market structures, indicating that no particular reform is the key. The current reality of financing in sub-Saharan Africa is such that even if allowed, the debt and equity funders of IPPs would not take the risk of an IPP directly selling to a wholesale market. Nor could debt/equity providers currently be expected to bear the risk of an IPP finding an alternative buyer in case a particular offtaker defaults.

As noted by Anton Eberhard in a recent World Bank report¹², an important lesson is provided by the second wave of power sector reforms that occurred in regions such as Latin America. Most Latin American countries had undergone a process of unbundling, privatization, and the establishment of wholesale spot markets. Even so, it became clear that long-term contracts with financially viable offtakers were critical to generate secure and reliable financial flows to pay for large investments. A second wave of reforms—as enacted in Brazil, Chile, Colombia, Panama, and Peru—shifted emphasis from prescriptions regarding unbundling, privatization, and the creation of wholesale markets (competition in the market), to the establishment of dynamic plans for long-term generation and transmission expansion.

In short, regulatory reform can only achieve so much progress on its own. Undoubtedly, once unlocked, the market will benefit from such measures. But more fundamental issues persist and inhibit development. In the case of the sub-Saharan African power market, this is primarily the creditworthiness of offtakers and the comparative lack of bankable long-term contracts.

“ As an intermediary AGC can facilitate the development of a multi-buyer model in the market. As a principal in the market, it can help create a trading environment, and ultimately help fulfil the vision of the SADC IPP Framework. **”**

AGC can cushion investors from regulatory changes by working with national and regional regulators to ensure that any regulatory changes are properly addressed through the PSAs and do not negatively impact upon the PPAs with IPPs. This will allow the delivery of much needed generation notwithstanding significant legal, regulatory and financial changes in the underlying markets.

4.3. Transmission Network

Each of the SADC countries (other than South Africa) is currently unable to meet national electricity demand due to (a) limited generation capacity and (b) poor transmission and distribution infrastructure. This section reviews the status of the current transmission network and potential geographies and projects for AGC implementation.

SAPP has the most established grid interconnection of the power pools in the region. There are twenty active cross-border interconnections in the SAPP, detailed in Table 5 below.

¹² For further details please refer to Independent Power Projects in Sub-Saharan Africa, Lessons from Five Key Countries by Anton Eberhard, Katharine Gratwick, Elvira Morella and Pedro Antmann, 2016.

Table 3: SAPP Cross Border Transmission Lines

No	From Country	To Country	Voltage (kV)	Transfer Limits (MW)	Notes
1	Zambia	DRC	220	500	2 lines
2	Zambia	Zimbabwe	330	1400	2 lines
3	Zambia	Namibia	220	300	1 line, can be uprated to 600MW
4	Zimbabwe	Mozambique	400	450	1 line
5	Zimbabwe	Mozambique	110	70	Radial line
6	Zimbabwe	Botswana	400	350/600	Higher N transfer
7	Zimbabwe	Botswana	220	250	Normally operated as radial line
8	Botswana	South Africa	400	650	1 line
9	Botswana	South Africa	132	150	3 lines
10	Botswana	South Africa	132	70	Radial line
11	Mozambique	South Africa	533	2000	2 DC lines
12	South Africa	Mozambique	400	1450	Direct to MozaL
13	South Africa	Mozambique	275	250	1 line
14	South Africa	Swaziland	110	150	1 line
15	South Africa	Swaziland	132	230	2 lines
16	South Africa	Swaziland	400	1450	1 line
17	South Africa	Lesotho	132	230	2 lines
18	South Africa	Namibia	220	250	2 lines
19	South Africa	Namibia	400	500	1 line
20	Swaziland	Mozambique	400	1450	1 line to MozaL

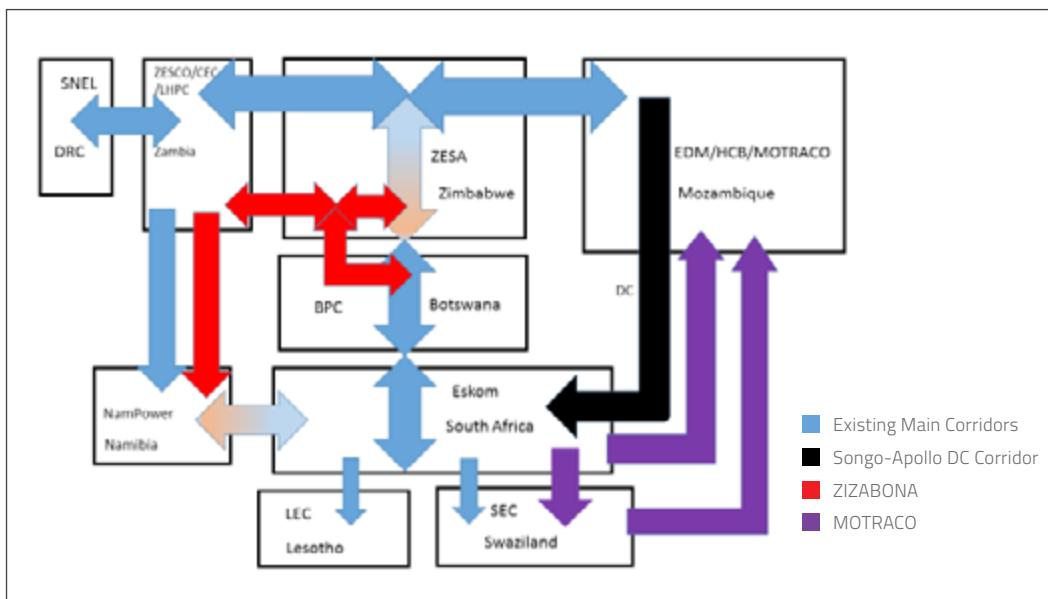
4.3.1. Transmission Expansion Plans

SAPP has transmission expansion plans for integrating non-operating members (Malawi, Tanzania and Angola) as a top priority, relieving congestion, evacuating power from new generation projects and grid strengthening/expansion. These are shown in Table 4 below.

Table 4: Planned SAPP Transmission Network projects

SAPP Transmission Priority Projects: IRENA Report 2015				
Project Category	Project Name	Planned Capacity	Planned Date	Status
Interconnecting non-operating members	Mozambique - Malawi	300	2020	Implementation planning
	Namibia - Angola	400	2022	Feasibility study terms of reference
	DRC - Angola	600	2022	Feasibility study terms of reference
	Zambia-Tanzania-Kenya (ZTK)	400	2019	Work in progress on Zambia- Tanzania side. Feasibility study on Kenya-Tanzania
Relieving Congestion	Zimbabwe-Zambia-Botswana-Namibia Interconnector (ZIZABONA)	600	2019	Implementation planning. A special purpose vehicle established and registered in Namibia 2016
	Central transmission corridor, Zimbabwe	300	2016	Work in progress and feasibility study review
	Kafue-Livingstone upgrade, Zambia	600	2014	Line has been commissioned
	North-West upgrade, Botswana	600	2018/20	Implementation planning
Evacuating power from new generation	Mozambique backbone phase 1	3100	2024	Implementation planning
	Mozambique backbone phase 2	3000	-	Implementation planning
	2nd Mozambique-Zimbabwe	500	2022	Feasibility study
	2nd Zimbabwe-South Africa	650	2022?	Feasibility study
	2nd DRC-Zambia	600	2016	Line has been commissioned

Taking the existing and planned connections together, the regional interconnection in SAPP is depicted below.



4.3.2. Transmission Congestion

Detailed information on transmission congestion, current transmission losses and SAPP organizational rules can be found in *Annex 3 (Africa GreenCo Technical Feasibility Report)*. This annex provides details on SAPP standard practice when handling wheeling, losses and congestion such that both seller and buyer pay each 50% of a SAPP predetermined wheeling charge on a wheeling route. Losses are compensated based on the market clearing price.

“ Congestion is resolved through market splitting with higher prices in the zone downstream of a congestion point. Whilst there is a high level of congestion on the current SAPP network, it is not always necessary to physically wheel power from a given seller to a given buyer – power can be delivered by displacement (i.e. power imported at the import point may be physically consumed by an end user near the import point rather than flowing to the export point; a corresponding amount of power generated by a generator near the export point may instead be exported by the wheeling utility at the export point. The imports and exports at each end of the transmission network balance each other out).

4.4. Identification of a regional project to prove concept

A suitable project to prove the AGC concept must have:

- capacity to supply power/energy;
- a market for the supply; and
- a transmission path between the Generator and the Offtaker(s).

A proper test of the concept's robustness should include proof of multi offtake by entities in different countries (fostering regional integration and diversification of risk especially payment default); it should also (i) test transmission operations (i.e. capacity reservations, prioritised allocation, wheeling charges, losses, congestion, investment requirements, etc.); (ii) market operations (participation in bilateral and competitive markets, power/energy tariffs, settlement issues, payment guarantees etc.); and (iii) regulatory requirements (licensing, market/grid codes, SAPP membership, tariff regimes, PPA requirements etc.).

To test AGC's trading ability, an opportunity based on surplus power in the region would be most favourable for short term implementation because there would only be energy supply transactions to be addressed without

investment issues as the supplying plant will be already installed and functional. Such an opportunity may exist in South Africa and/or East Africa and will be investigated further with the relevant South African and East African counterparties.

While it may be more beneficial to test the AGC concept by supporting a new IPP in order to demonstrate AGC's ability to facilitate new generation capacity, the development of a new IPP can be expected to take a number of years. In order to gain momentum and build an initial portfolio, it is therefore worth considering AGC assuming the offtake obligations under existing PPAs. In doing this, AGC would step into the current offtaker's shoes under the PPA and enter into a PSA with such offtaker. The key benefits for the Generator and the Offtaker would be the same as under a new IPP – the Generator would acquire a more creditworthy counterparty and the Offtaker's (and its host Government's) current contingent liabilities would be reduced as a result of AGC's reduced requirements in terms of termination payments and credit support for the Offtaker. There would need to be an adjustment of the tariff to allow for AGC's margin, but the parties may accept this in return for the benefits of AGC's involvement. The main benefit this structure would not immediately achieve is a reduction in the Generator's financing costs as these would already have been entered into. There may however be scope for the Generator's debt to be refinanced with AGC as its key contractual counterparty. For further details of AGC's proposed contracting structure and risk allocation, please refer to *Section 7.6 (Allocation of Key Risks in AGC's PPAs and PSAs)*.

A further possibility may be for AGC to work with existing Generators with a view to them building additional capacity and expanding their operations, selling the additional power to AGC using the existing network connections. This would have the advantage of being able to use, amend or replicate some of the existing contractual arrangements and enable AGC to work with a Generator who is already familiar with the local market and its technical and operational constraints

4.5. Scope of evaluation

This section considers the main variables when identifying suitable projects for AGC to target.

4.5.1. Geographies

There is currently an urgent energy deficit in Zimbabwe, Zambia and the DRC due to an ongoing drought situation, as well as a general regional supply deficit. Botswana frequently experiences power shortages due to poor performance of its new plant (Morupule B). Namibia, which is reliant on imports, is also affected by the regional power shortage and the prevailing generation shortfall in Mozambique is compounded by the current drought. Any new plant in the above countries, with a good energy supply, would alleviate the current supply shortage. Except for Namibia, these countries are not endowed with wind power but they all have abundant solar energy. Botswana and Namibia have high irradiation (insolation) levels due to their vast arid areas.

While AGC intends to operate at a regional level, it may take considerable time to secure agreement among multiple member countries within SADC and negotiate the terms under which a new regional entity is formed. The concept could however be tested in one of the SADC countries and subsequently rolled out within the region.

Our technical due diligence identified Zambia, Botswana, Mozambique and Namibia as the most suitable countries for a potential pilot project. These countries were selected because:

The countries' utilities are active trading participants in the SAPP;	The countries lie in the critical trading corridors; and	The countries are endowed with renewable energy potential.
---	--	--



South Africa, the largest trading partner in SAPP was not considered at this stage even though the proposed intermediary's role could be beneficial to help move some of the potential surplus generation of power from SA to other SAPP countries. The success of the REIPPPP and the domestic power planning mean that the local market is well served (if not saturated) at this point. However, AGC recognizes the value of the strategy undertaken by the REIPPPP and seeks to replicate the transaction execution framework in the region. The REIPPPP office is looking to expand operations in the region and might be an important partner for AGC as they implement this strategy. In addition, there is scope to support the construction of new IPP assets or add new capacity to existing renewable energy plants for regional export via AGC in South Africa purely for cross-border trade through long term PPAs/PSAs. This approach would reduce some of the risk for construction and O&M as well as the medium term default risk; however, for the time being AGC's focus is on generating assets outside of South Africa to address utilities' current IPP pipelines.

4.5.2. Project Size

The target project size, particularly during the initial stages, is an important consideration. On the one hand, AGC aims to be able to work at scale in order to maximize the impact on the efficiency of the transaction process and work on projects sufficiently large to benefit from multiple offtakers. On the other hand, acting as a creditworthy offtaker to very large projects before AGC has established itself as a viable market player will require substantial capital to backstop each transaction, and will reduce AGC's medium term capacity to develop a diversified portfolio. AGC's initial target project size is therefore between 5-100MW. For those over 100MW, AGC will need to source substantial capital (USD150-200m) and would take concentrated risk; and once AGC has established track record through a portfolio of PPA/PSAs, has a sufficiently a large capital base and diversified exposure, it does anticipate acting as an anchor offtaker for larger projects.

4.5.3. Technologies

Given the target project size of 5-100MW, the energy sources to be considered are hydro, solar, wind, geothermal and biomass. All of these technologies are technically and financially viable in many of the countries of the SADC region and technology costs continue to decline. As noted by the African Development Bank, Africa cannot power its homes and businesses unless it unlocks [its] huge renewable energy potential, and combines it with conventional energy to light up and power the continent¹³. As a regional trader, AGC will assist in the transition to a low carbon economy by mitigating the potential volatility created by intermittent generation through optimum resource management on a regional basis – i.e. if the wind is blowing or sun shining in one country but not another, power can be redistributed across the region, whether physically or by means of off-setting, thus smoothing the peaks and troughs in a manner which cannot be achieved on a project-by-project basis.

Whether AGC should work exclusively with renewable technologies is an important topic for further debate with the founding members of AGC. The consistent message from the African States is that they need cheap, reliable power and are neutral as to the source of such power, citing in particular the heavy dependence most developed nations place on thermal power. While we are all agreed that a transition to a low carbon economy is in our global interests, the degree to which this should be led by developing countries is less clear, especially given the relatively weak transmission networks which are ill-equipped to deal with the intermittent nature of some renewable technologies (solar PV and wind). The AGC structure would be equally applicable to any technology and consideration should be given as to whether it may be desirable from a practical perspective for some despatchable, thermal baseload power to be included within the AGC portfolio. Including thermal power may also help AGC to increase its revenues and achieve scale more rapidly, enabling it to then support more renewable energy projects. However, the inclusion of thermal power in the AGC portfolio may also have an impact on the sources of funding available to capitalise AGC. This is a very important issue to be discussed and agreed between the founding members of AGC, recognising that the balance may change over time.

4.5.4. Project Type

Grid connected projects were preferred over off grid projects because of their potential for participation in DAM and multiple offtake structures, both of which are advantages for testing AGC's feasibility, including its core credit

¹³ African Development Bank's "New Deal on Energy for Africa" brochure

Target Market

risk mitigation strategies. A structure such as AGC could however support off grid projects through aggregation and diversification.

4.5.5. Project Shortlist

Mitigating the current power shortage in Zambia, Botswana, Mozambique and Namibia requires AGC to commit offtake on planned non-hydro renewable energy plants within these countries. Whilst Botswana experiences shortages at present, these are a result of limited installed capacity and not energy shortage as there is plenty of coal available. The country needs renewable energy from reliable sources to diversify its supply portfolio. Ideally, the new plants will be close to the load centres in order to minimise investment in transmission capacity, wheeling and losses. Projects that can supply multiple offtakers in the different deficit countries will be more attractive for proof of the AGC concept.

AGC may support the development of any one or more of the grid connected prospective IPP projects listed below for onward sale to multiple offtakers via PSA(s) under current SAPP transmission and interconnection realities.

Table 5: Non Hydro Renewable Energy Projects in Zambia, Botswana, Mozambique and Namibia

Country	Plant No.	Plant Name	Type of Energy	Capacity (MW)	Grid/Off grid
Zambia	1	GET FiT Solar Projects	Solar	Up to 50	Grid
	2	Eastern Province	Solar	10	Off grid
	3	Luapula	Solar	10	Off grid
	4	Lusaka	Solar	2 x 50	Grid
	5	Kapisya	Geothermal	2	Off grid
	6	Lamba National Forest	Biomass	4	Grid
Botswana	7	Solar CSTP	Solar	100	Grid
Namibia	8	DIAZ Wind - Luderitz	Wind	72	Grid
	9	InnoVent Walvis Bay	Wind	60	Grid
	10	Otjiwarongo	Biomass	20	Grid
	11	Ohorongo	Biomass	20	Grid
Mozambique	12	Otjikoto	Biomass	36	Grid
	13	Mocuba	Solar PV	32	Grid
	14	Metoro	Solar PV	30	Grid

In terms of larger scale projects, SAPP has a priority project pipeline to meet demand as indicated in the table below. Please note that some of the projects under Zambia were identified in the OPPPI presentation (25 April 2016 in Lusaka) and some under Mozambique were sourced from an EDM presentation of 29 August 2016. These are additional to the SAPP list.

Table 6: Large Scale SAPP Projects

Country	IPP No.	Name	Technology	Capacity (MW)	Expected COD
Zambia	1	Kafue Lower	Hydro	600/750	2017
Zambia	2	Mabmilima Falls	Hydro	425	2019
Zambia	3	Lunsemfwa Lower	Hydro	255	2020
Zambia	4	Kalungwishi	Hydro	247	2020
Zambia	5	Mpata Gorge	Hydro	543	2023
Zambia	6	Muchinga	Hydro	180	2021
Zambia	7	Luapula	Hydro	850/1200	
Zambia	8	Lufubu	Hydro	163, 326	
Zambia	9	Mulembo/Lelya	Hydro	300	
Zambia / Zimbabwe	10	Batoka Gorge	Hydro	1600/2400	2022
Zambia / Zimbabwe	11	Devil's Gorge	Hydro	1000	
Namibia	12	Baynes	Hydro	600	2018
Namibia	13	Kudu	Gas	800	2019
Mozambique	14	HCB North	Hydro	1245	2027
Mozambique	15	Mpanda Nkuwa	Hydro	1500	2025
Mozambique	16	Lupata	Hydro	600	2027



Zambia

If the projects in Zambia are implemented with AGC as the offtaker under a PPA, AGC could sell to ZESCO and CEC in Zambia; BPC in Botswana, NamPower in Namibia and/or any other offtaker in SAPP. Transfer of power is not likely to be affected by transmission congestion in Zimbabwe as current trade transactions are northwards from Eskom and Mozambique. However, the transmission path will be congested when the hydro generation gets back to normal levels in Zambia and the DRC. Alternative southwards transfer capacity for the power will have to be found as the central corridor will normally be congested. The route via the Livingstone-Caprivi DC Link to Namibia may be used if there is spare capacity and otherwise transnetwork delivery can be facilitated by displacement and other offtaking opportunities might be sufficient for non-physical transfer of power. The other alternative would be to commit to transmit of a portion of the power through the ZIZABONA and/or other new transmission and interconnection projects as listed in table 7 and facilitate its/their implementation by increasing anchor transactions.



Botswana

If AGC were to enter into a PPA with the CSTP in Botswana, it could sell the power to BPC, Eskom, NamPower or any other off takers in the southern countries. Sales northwards to Zimbabwe may be possible if ZESA claims its transmission rights on the Phokoje – Insukaminin line but Zimbabwe is currently not a favoured business destination. Sales northwards to Zambia, DRC or part of Mozambique will not be possible due to transmission congestion in Zimbabwe during the drought period. Northwards transfers on the Caprivi link will not be possible as this is normally a unidirectional transfer route towards Namibia. However the new DC technology employed may be able to permit reverse flows on special arrangements with NamPower that may allow displacement to take place. Under normal circumstances (no drought), northwards sales from Botswana will increase transfer capability through the central corridor due to counter flow / displacement trade.



Namibia

Whilst all the projects in Namibia can be implemented to reduce power/energy shortage during the drought period, the biomass projects are based on unproven encroaching bush fuel and will not be considered by AGC at this stage. AGC could commit to promote and offtake from the two wind projects for onward sale to NamPower, Eskom, BPC or any other off taker in the southern countries. Export northwards from Namibia through Eskom, displaces imports into the Southern Cape from Mpumalanga, thereby increasing transmission capacity through such counter flows. If there is no corresponding increase in southward flows to Cape Town on the lines, losses will be reduced. However, Namibia cannot export through the Caprivi link because it is normally unidirectional. It also cannot export beyond Botswana due to congestion in Zimbabwe.



Mozambique

Mozambique has two solar PV plants with a combined capacity of 62MW planned to come online in 2017. Because Mozambique is also drought stricken, the output from these plants is likely to be consumed locally. External sales of the availed capacity to Zambia, Botswana, Namibia or any other country in the south, will require transmission capacity through Zimbabwe or in South Africa. Transmission congestion problems in Zimbabwe will inhibit/limit the trade. The Songo-Bindura line is scheduled to transfer 400MW for Eskom from HCB if ZESA is not utilizing part of the capacity. At present ZESCO of Zambia is utilizing part of the capacity for its emergency power supplies located in Mozambique, but if through AGC ZESCO is able to secure more generation capacity domestically, it will require less capacity on this line. Any use of capacity on the line will require negotiations among EDM, ZESA Eskom and possibly Zambia.

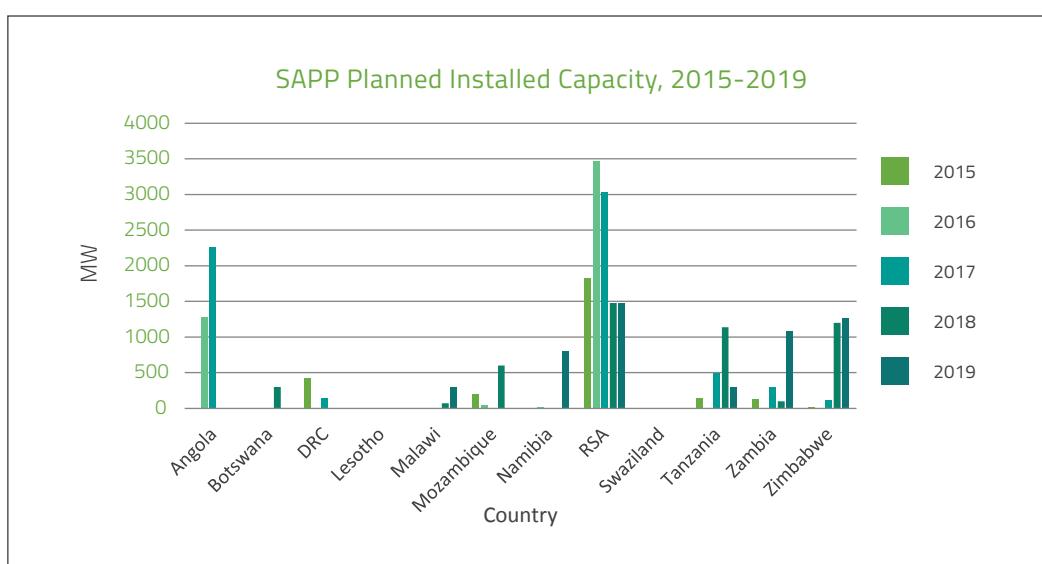
4.6. Proof of Concept Focus Country

Based on PPA Energy's technical analysis and as further outlined in *Annex 3 (Africa GreenCo Technical Feasibility Report)*, on balance, Zambia would seem the best choice for initial proof of concept. Apart from the Kafue Lower, Mpata Gorge and Luapula that are government projects in Zambia, the rest can be IPP facilitated. AGC can play its intermediary offtaker role in any of these. The bigger projects will require more financial resources than the smaller ones. AGC will select a project in the medium range (20-100MW) with potential for local supply and export. Kabompo, Lunsemfwa Lower, Muchinga and Kalungwishi fall in this category. Depending on how far LHPC has gone with the development of Lunsemfwa Lower, AGC may still become the offtaker. The GET FiT Zambia programme supported by KfW and DFID would provide a very good opportunity for AGC to commence its operations. The AGC team is in discussion with the relevant stakeholders with a view to AGC acting as intermediary offtaker on the GET FiT Zambia projects.

Zambia also has experience of non-State actors being involved in the power industry, with CEC playing a significant role. It may therefore be institutionally more prepared to interface with AGC than other more heavily State-owned markets. Our discussions with the Zambian regulator (ERB), national utility (ZESCO) and Ministry of Energy to date have been very positive and we look forward to working with them going forwards.

4.7. AGC's expansion opportunities within SAPP

In addition to the projects listed above and against the backdrop of increasing demand discussed in [Section 4.8 \(SAPP Cross Border Trading\)](#) below, there are a large number of additional projects planned within SAPP, with the largest contribution expected by South Africa, and large additional pipelines in Angola, Tanzania and Zimbabwe, as demonstrated by the chart below.



IRENA's Southern African Power Pool: Planning and Prospects for Renewable Energy analysis in 2013 and updated expansion plans provided in the SAPP Annual Report in 2015 include more privately financed projects in many of the SAPP member countries, driven by the expected improved financial viability and policy support for renewable energy IPPs. The targeted increase within SAPP – of more than 20,000MW of additional installed capacity by 2020 – is strongly linked to higher participation by IPPs (71% of 2017 additions) and a focus on renewable energy. Achieving these targets – both the quantum of new installed capacity and the role of the private sector – requires a dramatic change in the current IPP market. Developers will need predictable and transparent contracting regimes, financially viable tariffs and creditworthy offtakers – i.e. exactly the types of benefit accruing from AGC.

4.8. SAPP Cross Border Trading

Beyond the operating environment for working with IPPs on long term PPAs, AGC also plans to be take an active role in short term competitive markets – partially to fully engage with the regional power sector and partially to create the capacity to react to an offtaker default by selling power to an alternative offtaker as rapidly as possible. This section describes the main characteristics of the SAPP competitive power market.

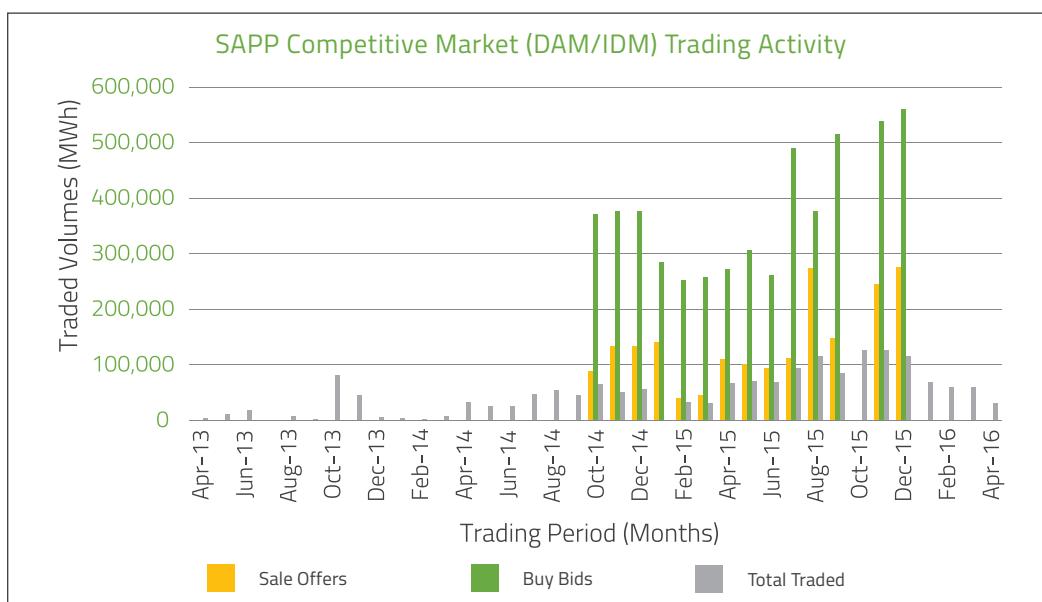
SAPP is the most mature regional market in Africa in terms of active and open trading infrastructure to support an AGC trading role – with a Day-Ahead Market (DAM), an Intra-Day Market and, as of March 2016, a Monthly and Weekly Forward Physical Market - supplementing a market which is otherwise largely dominated by bilateral contracts. The bilateral market consists of long term and short term contracts that may be firm or non-firm with the latter being currently prevalent due to shortage of supply. The DAM is the main market operated by the SAPP Co-ordination Centre in Harare. Table 7 below shows some of the current SAPP bilateral trade.

Table 7: Major SAPP Bilateral Contracts, 2016

No	Contract	Seller	Buyer	Volume	Firm/Non-Firm
1	EDMN-BPC- via -ZIM	EDM	BPC	50	Non Firm
2	EDM-BPC- via- RSAN	EDM	BPC	300	Non Firm
3	ESKOM-BPC	RSAN	BPC	50	Non Firm
6	EDM-CEC- via- ZIM	EDM	CEC	300	Non-firm
7	ESKOM-EDM	Eskom	EDM		Non Firm
8	HCB-ESKOM-via- ZIM	HCB	Eskom	400	Firm
9	HCB-ESKOM- HVDC	HCB	Eskom	2000	Firm
10	ZESCO-ESKOM- via - ZIM	Zesco	Eskom	300	Non Firm
11	EDM-LEC	EDM	LEC	150	Non Firm
12	ESKOM-LEC	Eskom	LEC	200	Non Firm
13	EDM-SEC	EDM	SEC	50	
14	ESKOM-SEC	Eskom	SEC	-	Non Firm
15	ZESA-NAMPOWER- via RSAN	Zesa	NamPower	300	Firm
17	ESKOM-NAMPOWER	ESKOM	NamPower	-	Non Firm
18	EDM -NAMPOWER	EDM	NamPower	-	Non Firm
19	EDM-ZESA	EDM	Zesa	280	Non Firm
20	HCB-ZESA-1	HCB	Zesa	40	Firm
21	MOZS-ZESCO via ZIM	EDM	ZESCO	60	Non Firm
22	MOZS-ZESCO (AGGREKO)	EDM	ZESCO	60	Non Firm
23	EDMN-ZESCO- via ZIM	EDM	ZESCO	60	Non Firm
24	ESKOM-ZESCO via ZIM	EDM	ZESCO	200	Non Firm
25	ESKOM-ZESCO via NAM	EDM	ZESCO	60	Non Firm

SAPP 2016 Data

The DAM and Intra-day market represented 5-10% of total cross-border power trades in 2015, but as the chart below shows, this has grown rapidly over the last 2 years. This growth in trading activity reflects the development of a robust power trading platform for SAPP in Harare – and with it, increasingly sophisticated and well-managed execution of trades and wheeling of power.

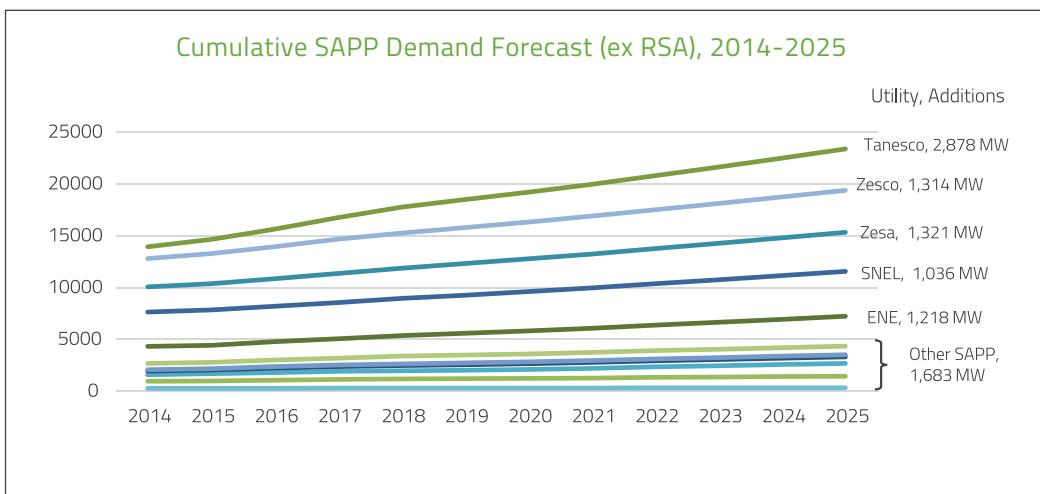


Target Market

Average monthly trading volumes have grown to between 50,000 and 100,000 MWh. The 2016 fall in trading volumes in part relates to the impact of Southern African regional drought on total generation in the SAPP market – and with it the capacity to trade more. 2014-2015 saw USD 25m total trading turnover; in 2016, this turnover has almost doubled, now averaging USD 5m per month.

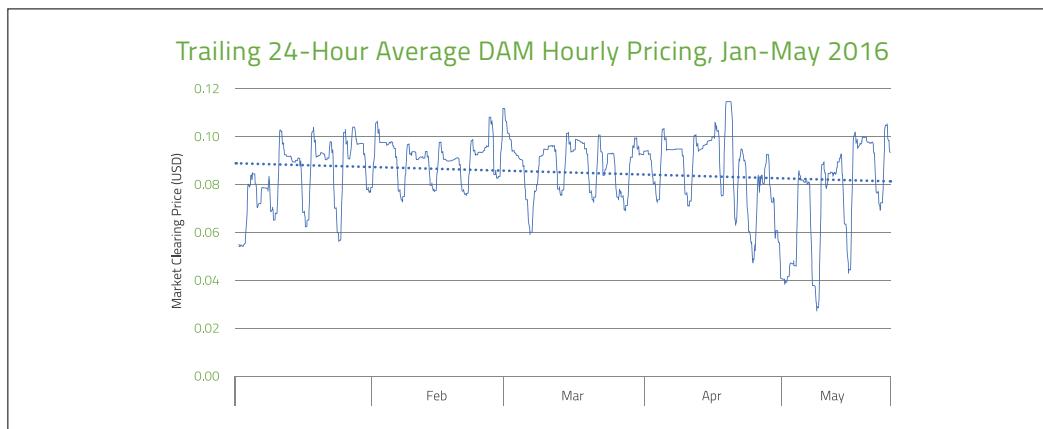
While these traded volumes have grown dramatically over the last three years, (150% year on year growth in 2015 vs 2014), the capacity for further trade is demonstrated by the number of buy bids and sale offers; the demand for power is around 3-4 times the actual traded volume. Market growth can be expected as the SAPP market develops new products (March 2016 saw the addition of the Forward Monthly and Weekly contracts), and as the utilities and other key stakeholders in the market increase trading capacity and local demand and supply increase.

In terms of the demand, SAPP forecasts that demand for power will grow by 40% over the next ten years to 2025. The key markets driving this growth are RSA, Tanzania, Zambia, Botswana, Mozambique, Malawi and Angola. These growth projections must also sit within the wider African energy access policy context; consumer (household, as well as commercial and industrial) demand for power tends to be highly inelastic and grow exponentially as the marginal use of additional electrical equipment etc. rises. How this translates into market demand for the SAPP grid will depend on utilities' ability to connect and collect from new and existing customers; but, beyond South Africa, demand is likely to increase beyond these projections.

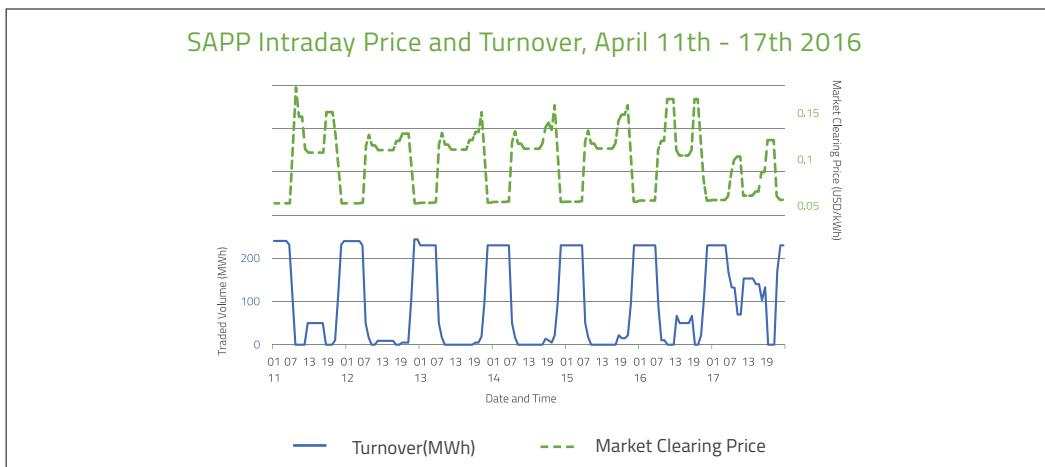


4.8.1. Price and Volume Trends

Price fluctuations on the traded markets tend to be in the range of 7-10 cents per kWh. The average monthly market clearing price is 8.5 cents per kWh.



On a monthly/weekly basis, peak demand is during the working week, in line with general economic activity. On an intra-day basis, the peak trading turnover period is overnight – when prices are at their lowest (typically around USD 6 cents per kWh). However the average Market Clearing Price is higher due to trading activity in the morning and evening. Daily prices spike up to as high as USD 18 cents per kWh. Over the weekend demand patterns are less consistent – and prices are typically lower.



4.9. AGC Strategy in SAPP

AGC will seek to be a member of SAPP so that it can operate within the SAPP trading environment. Any 'Electricity Supply Enterprise' situated in a SADC country is eligible to become a member of SAPP subject to the approval of the SAPP Executive Committee. An Electricity Supply Enterprise from a non-SADC member state may become a member of SAPP subject to the approval of SADC and any other conditions that may be stipulated. One category of Electricity Supply Enterprise is a Service Provider, being "an entity authorised by means of legislation or other consent to provide electricity market related services within the jurisdiction of its incorporation or establishment".

To join SAPP as a Service Provider, AGC will therefore need to be incorporated or established in one of the SADC countries or obtain special approval from SADC. For a further discussion on the impact of AGC's legal structure on its relationship with key stakeholders and market participants, please refer to Section 3 of *Annex 4 (Africa GreenCo Corporate Structure, Regulatory and Governance Options)*

Since AGC intends to be signatory to PPAs as an offtaker and a seller through PSAs within SAPP, it will be providing electricity market related services and therefore satisfy the definition of a Service Provider. Service Providers are entitled to trade within SAPP and AGC will become an "active market participant (trader)" when it avails part of project capacity to the SAPP administered DAM and other markets, which will entitle it to sit on the Executive Committee, Management Committee and Markets Subcommittee and be an observer in the Operating, Planning and Environmental Subcommittees.

Application for membership is made to the SAPP Coordination Centre Manager who will provide standard forms to be filled and returned for submission to the Management Committee. Membership is granted on the basis of a two-thirds majority. AGC's application will need to be supported by its host country national utility. AGC will discuss these intentions with the host country national utility to seek permission to apply to the SAPP Coordination Centre Manager who will in turn seek official clearance from the host country on behalf of AGC. As AGC will require the approval of at least two-thirds of the existing members of SAPP in order to be permitted to become a member, it is vital that AGC garners sufficiently broad political support within SAPP in order to achieve this. The AGC concept has been presented to the SAPP Management Committee and we are hoping to be invited to both the SAPP Management Committee and Executive Committee meetings in 2017 in order to progress discussions regarding AGC's role and potential membership. A prospective member can request to sit in the SAPP subcommittees as an observer in order to understand proceedings, and AGC will seek to do this prior to full membership.

It is envisaged that AGC's primary role within SAPP will be as an intermediary offtaker, but through joining SAPP, it will also have the ability to trade, whether in case of default by an incumbent Ofttaker, in order to sell surplus power, or to purchase and sell short term power outside of AGC's core PPA/PSA transactions. AGC's proposed operating strategy is summarised in *Section 5 (Financial Viability)*.

5

Financial Viability

AGC's objective is to be an independent organization that is financially sustainable.

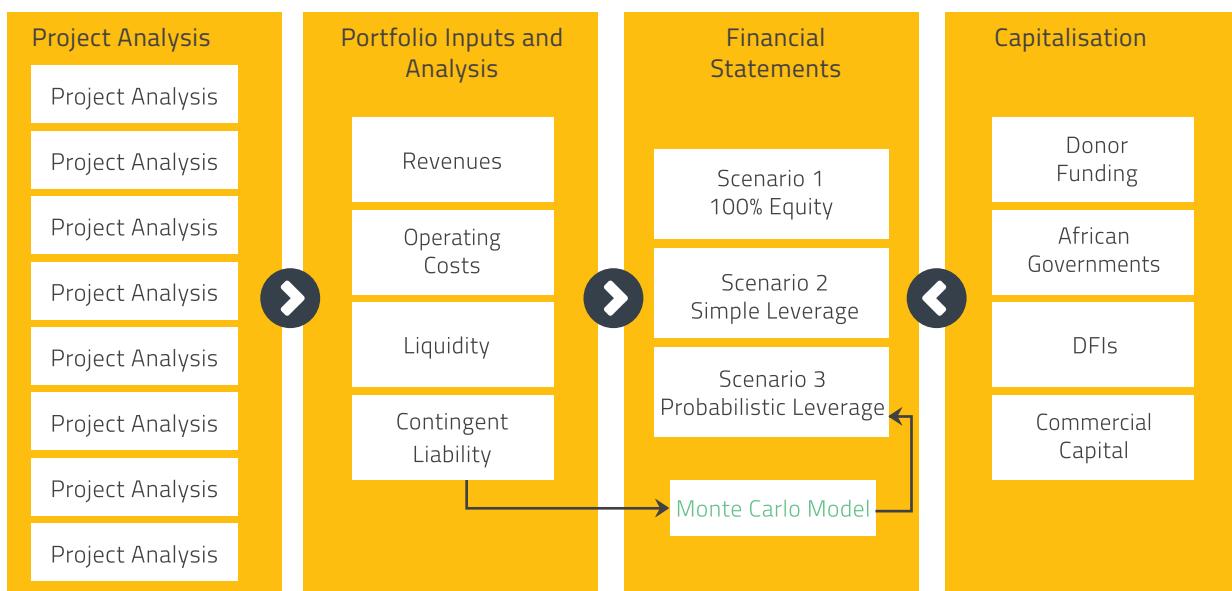
Understanding the financial implications of AGC's overarching strategy and potential legal and governance structure is at the heart of the Feasibility Study. The main questions that the financial viability assessment seeks to address are:

- ⌚ What sort of revenues could AGC generate and how?
- ⌚ What are the costs associated with implementing the AGC strategy?
- ⌚ What quantum of capital would be required for AGC to be considered creditworthy?
- ⌚ How could that capital be structured?
- ⌚ What types of investors could be targeted to contribute capital to AGC and what sort of return expectations could they have?

The model used to answer these questions has four components:

1. **Project Analysis**, which generates a simplified project finance model for different types of IPPs that can be supported by AGC, generating the financial performance of the underlying project and therefore the potential impact of AGC in terms of making more projects bankable;
2. **Portfolio inputs and analysis**, which is a set of assumptions building on a hypothetical portfolio of projects, trading activity, and operating inputs (e.g. staffing levels and compensation, costs for stakeholder engagement and governance) to understand the financial implications of different strategic decisions;
3. **Projected financial statements** across three leverage scenarios for AGC to determine the financial viability of creating an intermediary offtaker/power trading entity; and
4. **Capitalisation scenarios** that describe options for tranches of equity from concessional, local and private capital and the financial performance of different share classes under each of the leverage scenarios in 3. above.

The basic structure of the model is as follows:



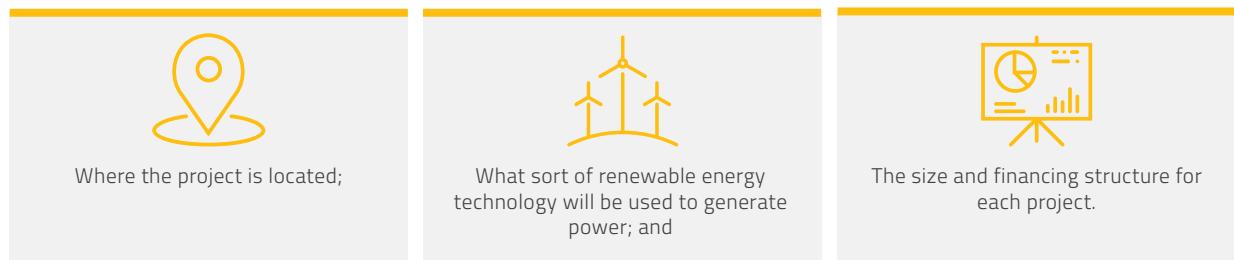
5.1. Project Analysis

To understand the relationship between AGC, IPPs, and the financiers – equity and debt – funding those IPPs, we have prepared a condensed project finance model for each renewable energy project that might be in the AGC portfolio. This model creates a simplified set of financial statements incorporating the following features:

Model Item	Description
Projected annual power output	Installed capacity x capacity factor x hours per year; no inflation
Projected offtake tariff	Installed capacity relative to three tariff bands for small medium and large IPPs
Upfront cost and build time	Installed capacity x CAPEX estimate per MW
Operating cost	Installed capacity x Fixed costs and Output x Variable Costs
Debt Schedule	Estimated leverage and tenor; interest rate benchmarked to sovereign and straight line amortization of debt
Project cash flows	What cash flows each project generates before and after factoring in any debt associated with the project (Project IRR and Equity IRR)
Termination value in each year of operation;	Payout to investors against their principal, lost revenues and wind-up costs. See Section 5.8.2 (Termination Value) below for full methodology
Financial performance of project given different debt parameters	Analysis of how improving creditworthiness of the offtaker – and therefore the project as a whole - changes the financial viability of the project through key indicators (EIRR, DSCR). Tariff impact

5.2. Hypothetical Portfolio

One of AGC's main design principles is to build a portfolio of PPAs with a number of IPPs and a number of PSAs with a number of Offtakers in order to reduce risk through diversification. The hypothetical portfolio can be tailored to reflect AGC's anticipated performance as it builds a portfolio of projects over time. The main inputs into the portfolio model are in terms of:



5.2.1. Country Inputs

On the basis of the technical analysis, the portfolio of projects is based in the SAPP, starting in Zambia and expanding to neighbouring countries over time. AGC anticipates being a Service Provider member of SAPP, piloting and operating within the SAPP structures.

5.2.2. Technology Inputs

The principal variable for each project is the type of renewable energy technology used. Using international benchmarks, this technology input is used to assess the estimated construction and operating cost and power output. The basic assumptions in terms of technology type are:

Technology	Capacity Factor	CAPEX	Fixed O&M	Var. O&M	Build Time	Dev't Costs
	Percent	USD/kW	USD/kW-yr	USD/MWh	Years	% Capex
Hydro - L	55%	2200	17.5	0	3	10%
Hydro - S	55%	2800	15	0	2	10%
Biomass	75%	2800	90	15	1	10%
Solar - S	27.5%	1650	15	0	1	8%
Solar - L	27.5%	1400	20	0	1	8%
Wind	35%	1800	40	0	2	10%
Geothermal	85%	2200	0	35	3	15%

These assumptions are benchmarked against a number of sources, including:

- ④ IRENA Generic Technology Parameters
- ④ Lazard Levelised Cost of Energy Analysis version 9.0 (2015)
- ④ Project-data on African Renewable Energy case studies reviewed by LHGP since 2009.

Factors to consider with respect to these assumptions are that:

- ④ Capital expenditure costs for African projects may be higher than in developed economies. For some of the hydro projects reviewed, capex reaches as high as USD3,500 per MW installed capacity; on the other hand, some technologies (solar, wind) are rapidly falling in price as manufacturing improves and innovations drive up efficiencies.
- ④ Development costs are also a higher percentage relative to the upfront cost in order to incorporate the higher general cost of doing business in Africa, especially in a regulated market as power supply.

5.2.3. Financial Inputs

The last component of the project level analysis is a description of the proposed financial elements of each project. The two key variables are:

Leverage

and

Tariffs

The ratio of debt as a proportion of total cost for most project finance transactions sits somewhere between 60% and 75%. Projects were given hypothetical levels of debt in 5% increments between these figures.

Current tariff levels across the SAPP and in SSA vary greatly depending on the technology, and the local context for investing in power. For renewable energy projects, three schools of thought have emerged around setting tariffs:

- ④ Feed-in Tariff (FIT) fixed at a set amount with any appropriate inflators as has been used in Kenya and Namibia and is pending for Ghana, Senegal and Uganda solar and wind projects;
- ④ Direct negotiation whereby investors provide their cost of capital and project costs and the tariff is set at a rate to generate adequate financial returns to investors and minimum bankability thresholds, as in Rwanda, Uganda, and Tanzania under the SPP program;
- ④ Reverse auction, wherein IPPs submit a proposed tariff under a procurement process and PPAs are awarded in part on the basis of lowest cost, used in South Africa and Zambia's Scaling Solar program.

Notes on how these approaches have been implemented are that:

- ▶ FITs in countries with a well-established renewable energy IPP environment (Uganda, Kenya) typically range from USD 0.09 to USD 0.12 per kWh.
- ▶ Feed-in tariffs tend to be higher (USD 0.15-USD 0.20/kWh) for smaller projects and for solar PV projects.
- ▶ Nigeria tendered for solar PV with a USD 0.17 per kWh feed-in tariff and selected pre-qualified bidders; as the process was delayed, some bidders suggested that they would be willing to implement the project on the basis of a USD 0.14 per kWh tariff; as a result, the Government restructured the tender to allow bidders to propose lower prices, and selected 14 projects for 1000MW+ installed capacity at tariffs around USD 0.115 per kWh.
- ▶ South Africa's reverse auction process ultimately yielded prices between USD 0.6 and USD 0.15 for its fourth and last major bidding round. These prices represent a large reduction in the four years from 2011, when the range was USD 0.14-USD 0.33 in 2011.
- ▶ IFC's Scaling Solar prices in Zambia have been published as Neoen/First Solar's USD 0.0602/kWh for a 47.5MW plant and Enel's bid of USD 0.0784/kWh for a 28MW plant in Zambia. This pricing is partially a function of falling solar manufacturing costs, but is also linked to a pre-approved concessional financing package from the IFC and is not necessarily a benchmark for attracting commercial investment.

Taking all of the available anecdotal and actual data points together, the Feasibility Study uses the following assumptions on tariffs:

Table 8: AGC modelled tariffs

Project Size	Installed Capacity		PSA Price (USD/KWh)
	Min (MW)	Max (MW)	
Small	0	15	0.10
Medium	15	25	0.09
Large	25	100	0.08

5.2.4. Hypothetical Portfolio

To test AGC's financial viability, these various inputs are combined into a portfolio of ten transactions across the SAPP. Some are linked directly to specific projects in the pipeline identified by AGC's technical advisors. Others are derived from conversations with developers and utilities about the type of mid-size renewable energy projects that they envisaged coming to market over the next five years or identified using the Power Africa Tracker Tool. Most initiatives, for example, Power Africa, ElectriFi, IRENA, and SEFA, forecast a large number of small-medium power projects coming to market over the next decade. In some cases the projects would not be viable in today's environment – for example, Malawi is not currently integrated into the SAPP grid, and Zimbabwe is a difficult environment for concessional capital. However, the expectation is that Malawi will become interconnected in 2020¹⁴ and that the political environment in Zimbabwe may improve sufficiently to enable AGC to support projects in these countries.

Table 9: AGC Hypothetical Portfolio Projects

Project	Country	Technology	Size (MW)	Leverage	Start Year	PPA Tenor
1	Zambia	Hydro	40	70%	1	25
2	Zambia	Solar	20	65%	1	25
3	Zambia	Hydro	80	65%	2	20
4	Mozambique	Hydro	20	70%	2	25
5	Namibia	Wind	25	65%	3	25
6	Botswana	Solar	40	75%	3	25
7	Malawi	Solar	20	75%	4	25
8	Mozambique	Biomass	10	50%	4	25
9	Namibia	Biomass	30	75%	5	20
10	Zimbabwe	Hydro	20	70%	5	25

From year 6 onwards – i.e. once these first 10 specific projects have been implemented, the Feasibility Study conservatively assumes 60MW of additional PPA contracting per year, using an average profile for a generic renewable energy project.

It may be possible for AGC to build its initial portfolio of PPAs by taking on existing IPP PPA contracts, shifting the offtaker role and risk from the incumbent national utility to AGC. Entering the market in this way would allow AGC to build a diversified, operational portfolio more rapidly than the incremental greenfield project approach described above. Potential entry points for AGC could include taking on some of the REIPPP contracts (e.g. for smaller projects), the Zambia Scaling Solar PPAs or equivalent.

The appeal for the existing investors and developers would be that the risk profile of their projects would improve, and refinancing may be more likely and on better financial terms. The benefit for the utility and sovereign would be the reduction in the contingent liability created by these PPAs – with more scope to concentrate on (and allocate budget to) other priorities.

However, this approach also raises a number of challenges. First, the investors may not be willing to undergo the additional transaction cost of reassigning contracts to AGC. Second there may not be any scope for AGC to

¹⁴ IRENA Report 2015

generate revenues through a margin on tariffs. Charging a margin requires either investors to accept lower tariffs on the basis of the improved offtaker creditworthiness or utilities to pay a higher tariff for the opportunity to help AGC become operational and improve their balance sheets.

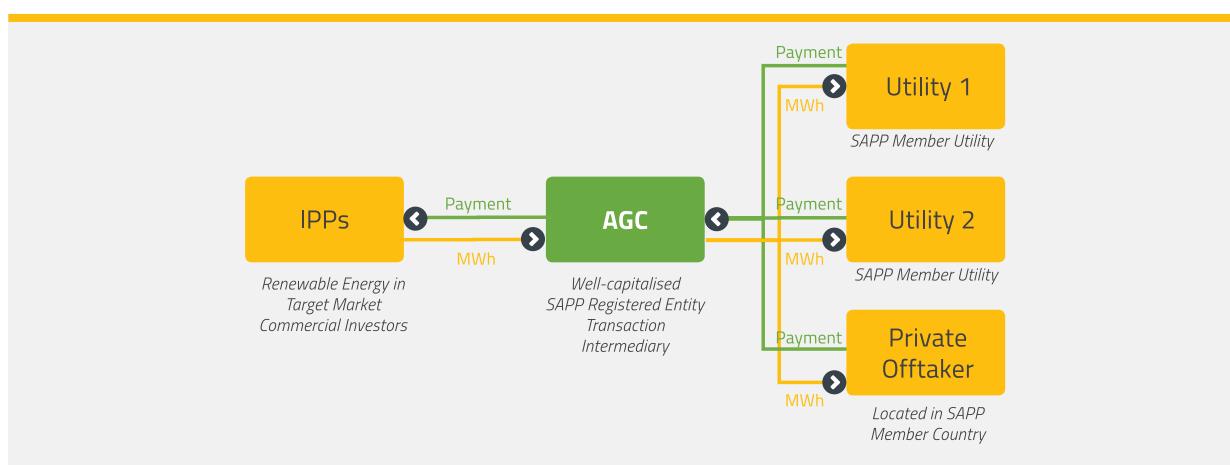
An alternative, lower impact approach would be to enter into agreements to purchase any surplus power under specific PPAs from the utility and sell it to alternative buyers via the SAPP bilateral and short term markets. This would entail AGC not intermediating between the IPP and utility on existing PPAs – simplifying the transaction required to build a larger portfolio more rapidly. However, this would do little to alleviate utility contingent liability concerns as the utility would remain the contractual counterparty to the IPP, but it would help to reduce the likelihood of the utility being contracted to purchase more power than it needs (which in turn makes it harder for the utility to pay for such power), and is similar to the short term trading model that already forms part of the Feasibility Study.

5.3. Operating Model

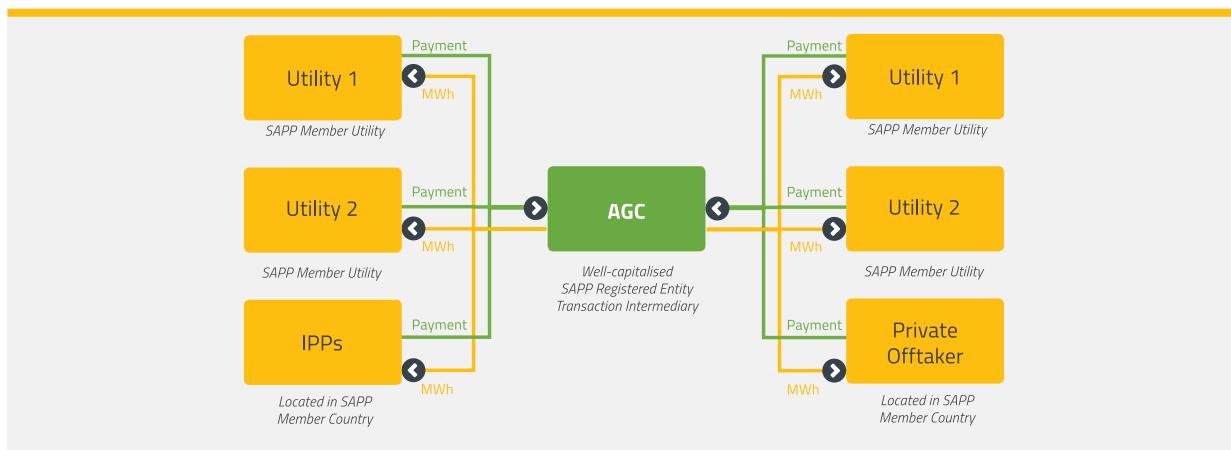
AGC has two core functions:

- i long term purchases of power from IPPs and selling to utilities and other offtakers, and
- ii short term power trading.

The principal way that AGC will achieve this is by sitting as a creditworthy offtaker for selected IPPs with standardised PPAs and PSAs. AGC aims to increase private sector involvement in renewable energy generation and as such, it will ensure that the terms of its PPAs are bankable and contain all of the key protections expected by investors in African power projects, as described in [Section 7.6 \(Allocation of key risks in AGC's PPAs and PSAs\)](#) below. AGC intends to work closely with SAPP, RERA, South Africa's IPP Office and other key stakeholders with a view to ensuring consistency across the various current initiatives aimed at standardisation.



AGC's second operating activity involves being an active trader in the power markets. AGC must be able to trade power in the market in order to implement its right under the PSA to divert power away from a defaulting Offtaker, as this represents the key risk mitigation mechanism it is able to deploy. Having such ability to trade, AGC may also potentially reserve a portion of the power generated under its PPAs to trade on the market in order to stimulate market growth and development. However, the viability of this trade will depend on the prices secured under the long term PPAs and PSAs. Current PPA pricing at around USDc10/kWh means that trading at the average SAPP day ahead market price between Jan-May 2016 of around USDc 8.5/kWh would not be rational; however, in light of rapidly falling solar tariffs, if a PPA were signed for less than USDc 8.5/kWh, it would be viable to take some market risk – remembering that the average price may fall, so AGC has long term exposure to market dynamics (see further [Section 5.4.3 \(Short Term Trading\)](#) below). Finally, it may make opportunistic power trades for financial gain. For the secondary impacts of AGC's cross-border trading role, see [Section 6 \(Impacts on Power Markets\)](#) below.



5.4. Revenue streams

AGC's operating strategy creates four potential revenue sources for AGC:

- ④ Sale of power purchased under long term agreements;
- ④ Sale of power on short term trades;
- ④ Income from invested capital; and
- ④ Sale of carbon credits.

The two core operating activities – acting as an intermediary offtaker and short term trading – will generate revenues through a margin applied to each unit of power bought and sold. This margin may vary based on the specifics of the actual projects AGC supports.

The third main source of income is significant as a financial contribution but is secondary to AGC's operating strategy. In order to be a creditworthy long term PPA counterparty, AGC will need a robust capital base. This balance sheet can be invested to generate returns. This investment component is the model of comparable entities that require a large balance sheet in order to do their business – but do not necessarily have large working capital requirements such as insurance companies, and guarantee facilities.

5.4.1. Offtaker Revenues

For its role as an intermediary offtaker selling power on to utilities/other offtakers through a PSA, AGC aims to select a margin level that generates a net reduction in the price of power paid by a utility/offtaker. The logic for achieving this net saving is that by acting as a creditworthy offtaker, AGC will:

- ④ Reduce the risk profile of the project;
- ④ Increase the tenor of debt invested in IPPs; and
- ④ Reduce the cost of debt and equity for IPPs.

Setting a hypothetical margin on the tariff is a critical decision; set too high a margin and AGC will eradicate any benefit created by being a creditworthy offtaker; set too low a margin and AGC may struggle to be financially sustainable.

Taking PTC as a case study, the margins applied to short term trades and long term PPAs in India have been carefully scrutinized and caps have been set to allow for long and short term power traders to generate sufficient returns to be financially viable. The basic ratios proposed by KPMG to the market regulator in 2009 were:



Trader Type	Margin
Low volume (<50 MWh)	4%
Mid volume (50-100 MWh)	2.5%
High Volume (100+ MWh)	1.5%

The Indian power sector regulator, CERC, set margins at INR0.04 (USDc 0.05/kWh) on power sales below INR3 USDc 4/kWh and INR0.07 (USDc 0.1/kWh) on power sales over INR3 USDc 4/kWh. Notably, this cap only applied after 7 years of active trading and when there were a number of active market traders (when the regulation was introduced there were 45 registered traders of whom 20 were active; as of 2015 there were 61 registered traders at IEX). Secondly, the margin cap was limited to short term power trading – for longer term power trades, no cap was introduced to allow market forces to determine prices and recognize the higher risk profile of long term power contracts.

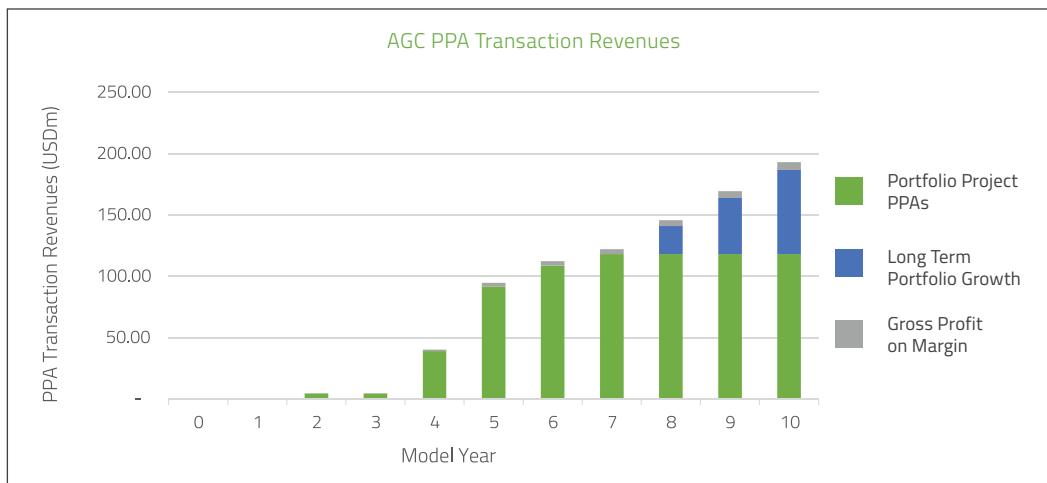
In the SAPP market there are no current regulations governing trading margins. AGC will be creating the market for independent intermediaries and focusing on longer term power purchase agreements – both of which entail higher risk. For modelling purposes the margin assumptions are:

⌚	USDc 0.3/kWh on power purchased from IPPs under PPAs and sold to utilities under PSAs – which is 3% of the average tariff values for IPPs (USDc 10/kWh);
⌚	3% on power traded in competitive markets, at an average price point of USDc 8/kWh – though noting that price volatility is as much as 100% so higher margins are very possible.

5.4.2. PPA Transactions

The volume of revenues from the intermediary offtaker role is determined by the power output of the IPPs included in the portfolio. The main assumption is that all power generated by the IPPs in AGC's portfolio is successfully transacted.

There is no immediate financial incentive to trade part of AGC's long term power commitments (unless in a default event). First, the SAPP average trading price of USDc 8.5/kWh is below the estimated long term PPA price range of USDc 9-11/kWh – so trading at the average price would entail incurring a loss. Second, some of the renewable energy projects (solar and wind) involve intermittent, non-despatchable generation, reducing, if not eliminating AGC's option of opportunistic trading during times when prices rise above the PPA tariff. Third, the risk of not being able to sell power purchased would create a substantial liability for AGC. With a margin of 3% on an average PPA price of USDc 10/kWh, AGC would need to sell 97.1% of power purchased in order to break even before operating costs have been deducted.



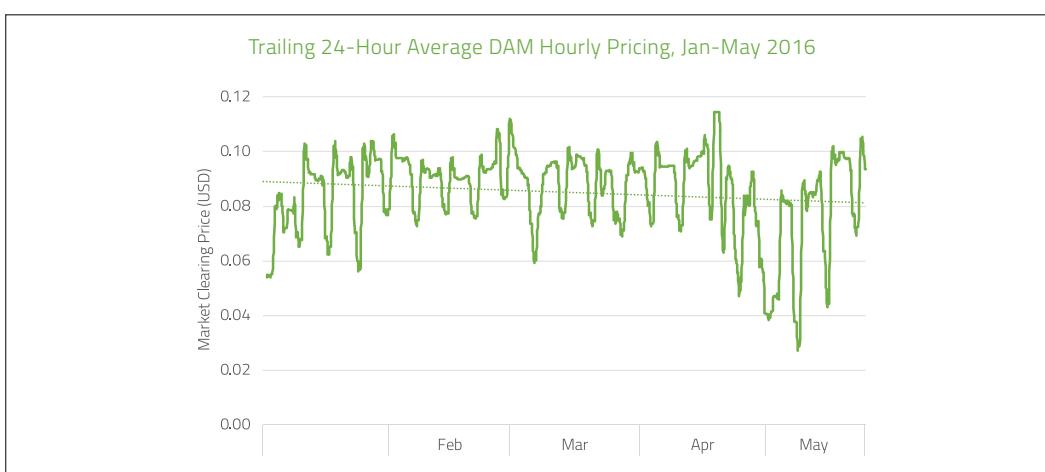
For the Feasibility Study, we forecast PPA revenues increasing to USD193.2m per annum, ultimately generating USD6.27m annual gross profit by year 8.

5.4.3. Short Term Trading

For short term trading, the AGC base model takes a conservative approach to the growth of the DAM/IDM markets and applies an estimated market share for AGC. SAPP's DAM/IDM markets have grown by around 120-150% annually over the last two years; however, SAPP's strategic objective is a more modest 10% long term growth. This growth is driven by a range of factors:

- ④ Increased investment in generating assets;
- ④ Increased investment in transmission and distribution with reduced congestion and therefore higher matching of traded power demand and supply;
- ④ Improved grid management and resulting lower transmission losses;
- ④ Increased market share of competitive market for cross border sales through additional products (e.g. the Forward Physical Weekly and Monthly Markets).

Price fluctuations on the traded markets tend to be in the range of USDC 7-10/kWh and as noted above, the average monthly market clearing price is between Jan-May 2016 was USDC 8.5/kWh.



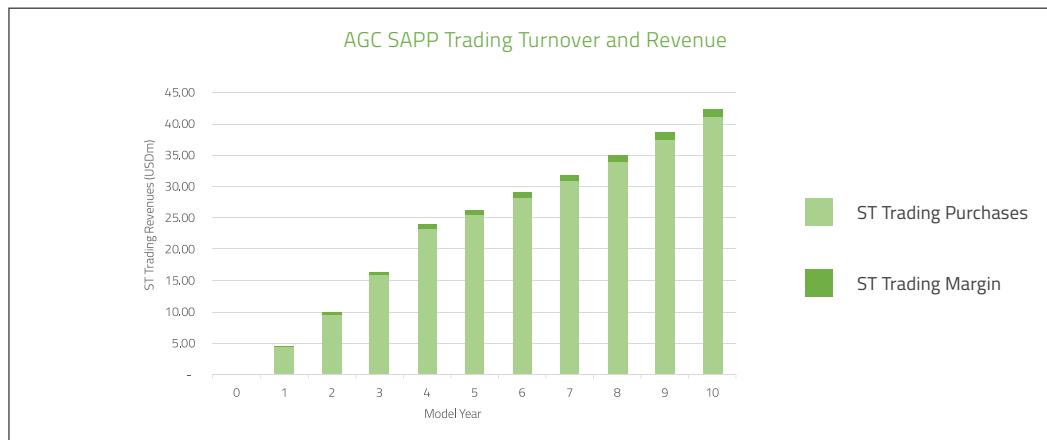
For the model, we assume SAPP's targeted 10% growth level – with competitively traded power growing from just under 1 TWh in 2015 to around 2.5 TWh in 2025. In 2016, total annual cross-border trading is 9 TWh. If the total cross-border trading grows from this level at a rate of 5% per annum over ten years, 2.5 TWh competitive trading would constitute 22% of the total market in 2025 – i.e. SAPP CC's 10% growth forecast for competitive trading volumes is ambitious but not outlandish.

Within that larger growth context, AGC will have to grow market share incrementally. For the sake of the Feasibility Study, we set a conservative long term market share target of 20%. Over the first four years of operation, AGC will grow its market share from 5% in Y1 to 10% in Y2 and 15% in Y3, and then hold steady at 20% of the total market from Y4 onwards. As a point of reference, PTC India currently has a 30% market share in India from a peak of 70%.



On this basis, AGC will ultimately trade over USD40m of power per annum, ultimately generating USD1.12m of annual gross profit. To put this in perspective, the total annual trading value on the SAPP was c. USD60m (USD5m per month) in 2016.

Direct operating costs (e.g. SAPP transaction fees, trading costs and transmission fees) are assumed to be allocated directly to the Generator and Offtaker in line with PTC India's approach. The power price run through the model is therefore the underlying cost per KWh – and the margin applies to this cost rather than the gross cost of delivered power.



AGC as a Trader

One of the main features of the PTC India story is that it was able to take a relatively small upfront investment and, by identifying and executing short term trades in an otherwise efficient market, generate substantial revenues, grow at a dramatic pace such that the IPO in year 4 raised \$30m and, perhaps most importantly, built PTC India's credentials as a counterparty able to manage risks and reduce IPP credit risk.

Given the large amount of capital required to launch as a PPA intermediary, this option may be attractive for AGC – it is a lower risk way to help grow cross-border trading in SAPP as a principal, build knowledge on the market drivers in practice and build a platform to take on long term power contracts in the future.

Adjusting the model used in the Feasibility Study can help to describe some of the implications of a pure trading model for AGC. The basic operating assumptions for market share and SAPP liquidity requirements are the same; the only changes are that:

- ⌚ There are no long term PPA contracts
- ⌚ The team no longer needs to be as large: the CEO and CFO lead a team of three traders, with one M&E professional and one admin;
- ⌚ No Annual stakeholder meeting

The key findings from a brief analysis of a trading-only strategy for AGC are that:

⌚	The break-even margin is 5% on a 20% long term market share;
⌚	The break-even volume to maintain a 3% margin is a long term market share of 32% of competitively traded markets – which would entail AGC turnover of around 750,000MWh / USD70m annually by year 10
⌚	Assuming 32% long term market share, the upfront investment requirement would be approximately USD3m, with capital calls tracking growth in revenues to around \$10m over the first 10 years
⌚	A margin of 5% on 32% long term market share would generate an equity IRR of 15%.
⌚	However, in contrast to the situation in India at the time PTC India was established, there are limited instances of surplus power to be traded as the majority of generation is tied up under long term arrangements. Trading is further hampered by transmission congestion. It is therefore currently unlikely that a trading only business plan would attract sufficient volumes to be successful.

5.4.4 Additional revenues for AGC can be generated from two indirect sources as set out below.

Investment Income

Additional revenues for AGC can be generated from two indirect sources. The capital required by AGC to fulfil its role as a creditworthy offtaker should be invested to generate income – it would be inefficient to keep it as cash. This approach is common for similar entities that need capital to be able to take on risk but do not have substantial working capital needs, such as guarantee facilities and insurance companies. The capital should be invested in a low risk portfolio – typically highly rated bonds and other fixed income securities so as not to erode the capital base (and with it AGC's creditworthiness).

The African Guarantee Fund (AGF) allocated USD55m of its USD90m capital base to be invested in 2014; 93% of this was in bonds, 6% in fixed deposits. Africa Trade and Insurance Agency (ATI) similarly had USD136m of its USD180m capital base invested, with 70% invested in bonds and 30% invested in floating rate instruments. The risk profile of these portfolios in 2014 were:

Table 10: AGF Treasury Portfolio Risk Profile

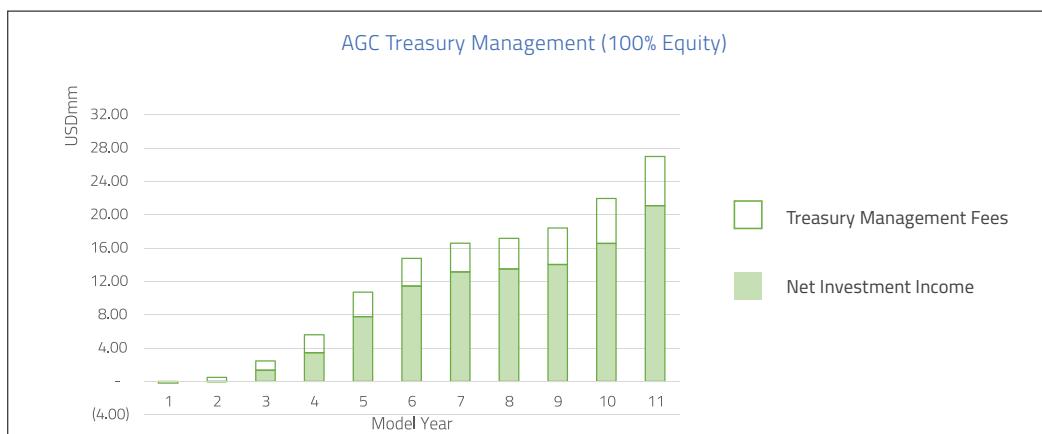
Rating	AGF	ATI
AAA	6%	22%
AA+	11%	41%
AA	37%	41%
A	5%	31%
A-	15%	31%
BBB	27%	6%

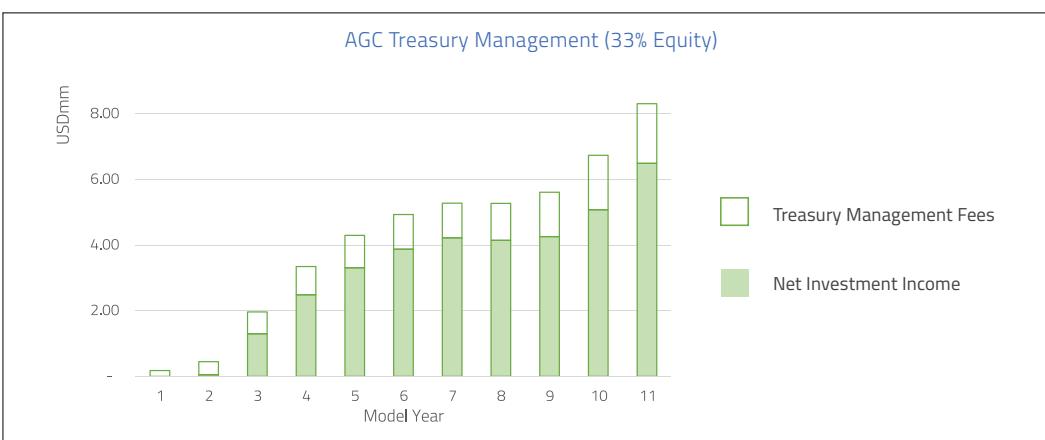
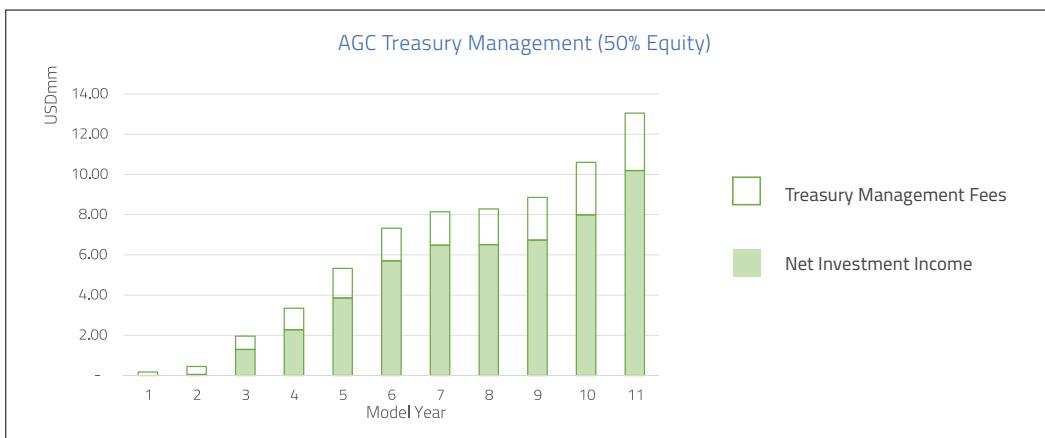
AGF's investment portfolio had a return of 2.39% in 2013 and 2.69% in 2015. ATI, on the other hand had a more conservative portfolio with 94% invested in securities rated A or higher. This lower risk profile comes with lower returns – ATI's returns on its bond investments were 1.37% in 2014, 1.19% in 2013. Investment income has been included in the financial model on the basis that all excess capital will be invested conservatively to generate 2.5% returns.

The assumption for the Feasibility Study is that AGC will outsource management of this capital to a professional asset management firm. Given the low return expectations/risk profile, the working assumption is that the fees paid out to invest the capital will be relatively low – 0.5% of assets invested.

Excess capital is defined as all capital not required to provide liquidity to PPA/PSAs and short term power trading, along with a cash cushion of 10% of the total capital available. Therefore, revenues generated from this investment activity vary depending on the capital structure that AGC is able to achieve. Under a base scenario whereby AGC is fully funded by debt and equity, there is more capital available to be invested; Under scenarios where AGC uses callable capital or is able leverage its balance sheet by using guarantees, the amount of capital available for investment is lower, since the neither callable capital nor any guarantee value will sit on AGC's balance sheet.

For each of the three leverage scenarios described in *Section 5.11 (Equity)* below, the investment income net of costs is as follows:



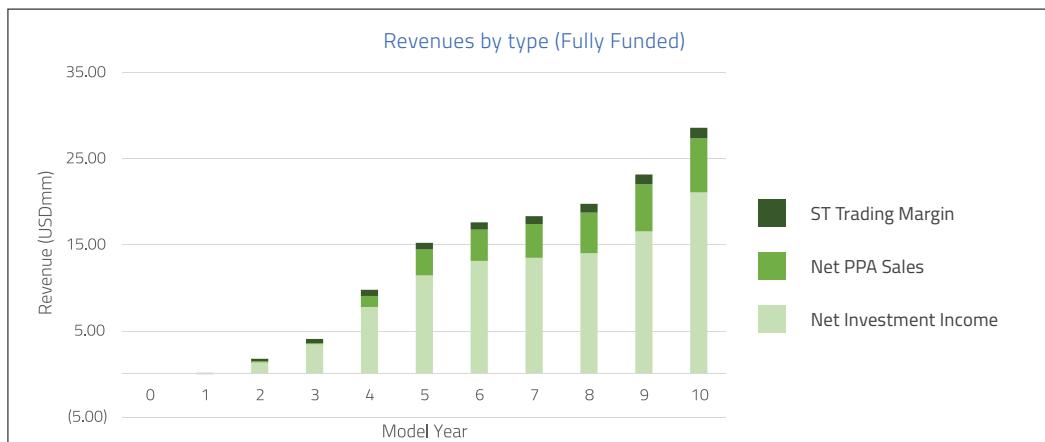


Carbon Credits

The second indirect revenue source is carbon credits purchased under the PPA. AGC intends to retain the rights to these credits (i.e. exclude them from the PSAs with utilities) and trade them if possible. Recent carbon market activity and current policy discussions suggest that there is not a reliable/credible source of income to be expected from carbon credit sales at present, but this may change.

Total Revenues

Taken together, these three revenue streams generate income for AGC in the following ratio, with investment income the largest contributor to value add (falling from 75% of revenues in year 10 if fully equity funded to around 50% if the capital base comprises 30% capital and 70% leverage).



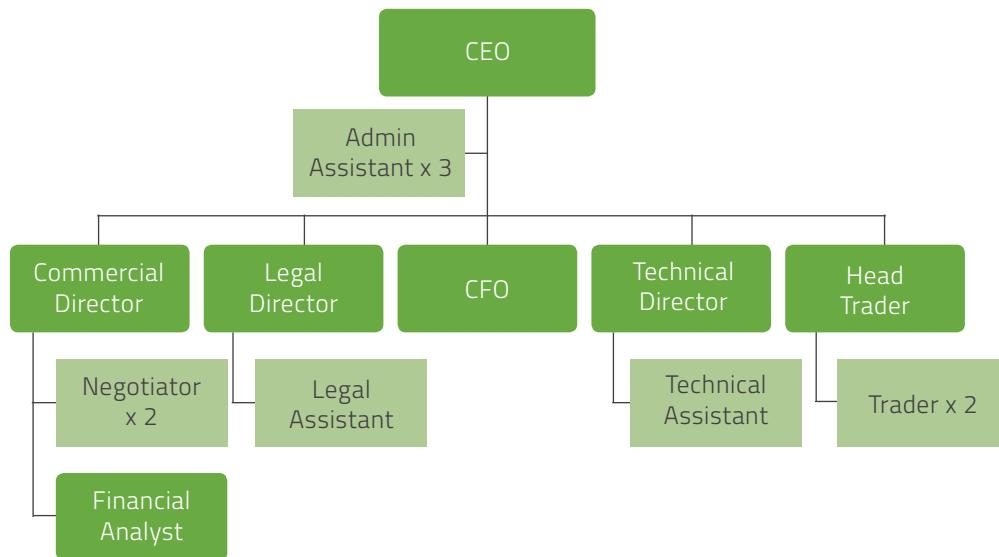
5.5. Operating Costs

Operating costs cover three key areas:

- ① Staffing and recruitment costs to put together a team able to execute the AGC strategy;
- ② Travel and office costs incurred by this team; and
- ③ Costs of governance in terms of board and stakeholder meetings.

5.5.1. Staffing and 3rd Party Expertise

The staffing plan is calculated on the basis of a lean transaction team with trading capacity. The forecast is more in line with a fund-type approach than a management company to mitigate high costs associated with the latter. In part this relates to the relatively small number of transactions to be executed each year (2), and in part this is a function of AGC's ability to leverage support from other initiatives focused on project preparation and power sector development. For example, AGC may be able to collaborate with the SAPP Project Acceleration Unit on transactions and therefore be able to leverage resources beyond the core team.



Staff Level	Salary (USD)	Year	0	1	2	3	4	5	6	7	8	9	10
CEO	250,000		1	1	1	1	1	1	1	1	1	1	1
CFO	200,000		1	1	1	1	1	1	1	1	1	1	1
Legal Officer	120,000		1	1	1	2	2	2	2	2	2	2	2
Transaction Team	120,000		1	2	4	4	4	4	3	3	3	3	3
Trading Team	150,000		1	2	2	2	3	3	3	3	3	3	3
M&E	40,000		1	1	1	1	2	2	2	2	2	2	2
Admin	30,000		1	2	3	3	3	3	3	3	3	3	3
Total			7	10	13	14	16	16	15	15	15	15	15

Beyond the base salary, the model includes 15% benefits, benchmarked against the Africa Guarantee Fund. In addition, the model budgets for average per team member recruitment fees of USD25,000 per staff member; while the cost of hiring junior staff will likely be lower, senior staff recruitment may require support from head hunters / executive search companies – USD25,000 is an average. Taken together staffing costs peak at USD2.48m per annum before falling to USD1.74m (inflation is excluded from the model).

This is relatively lean team but should be suitable for an average transaction rate of two PPAs per year. To supplement this team, the budget also allows for up to USD200,000 support for each transaction to engage country, technical, financial and legal advisors, and professional auditing at USD25,000 per annum.



5.5.2. Office and Travel

In order to operate the business, it is envisaged that AGC will have an office within the target region (Southern Africa). This office will require furnishing, and each staff member will be equipped with IT and other office equipment. The rental cost is budgeted at USD8,000 per annum per team member, which is benchmarked against prices in Nairobi and Johannesburg. Equipping the office accounts for an additional USD5,000 per team member, and ongoing IT support and subscriptions amount to a further USD25,000 each year.¹⁵

In order to develop, execute and monitor transactions, the team will travel widely within the region. In addition, the model budgets for international travel to ensure stakeholder engagement in the global infrastructure and climate finance communities. Taken together, these costs amount to USD250,000 per year.

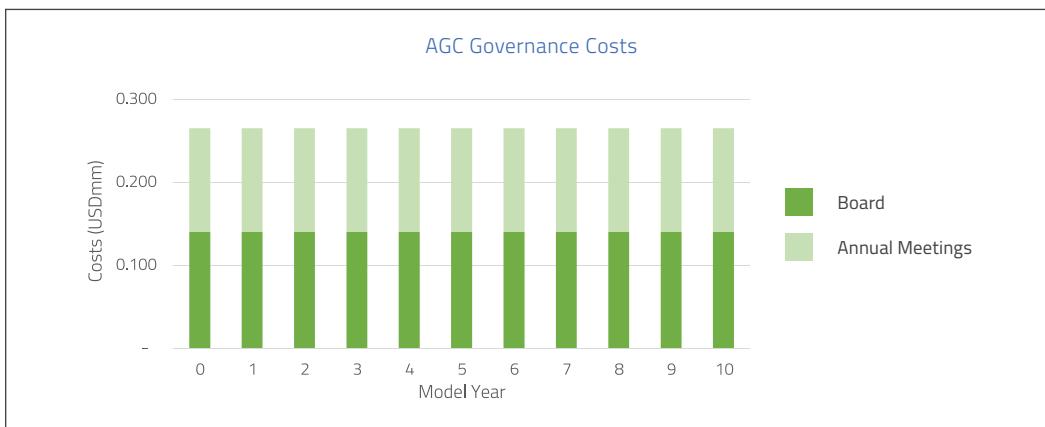


5.5.3. Governance

AGC as a recipient and steward of public capital will require a robust governance structure discussed in *Sections 8.2 (Governance), 8.3 (Risk management)* and *Annex 4 (Africa GreenCo Corporate Structure, Governance & Regulatory Options)* of this Feasibility Study. The main component of this oversight sits with the TopCo¹⁶ Board of Directors. The model operates on the assumption of 7 directors meeting physically twice a year. In addition, as a high profile development finance entity operating in the power sector, AGC anticipates holding wider stakeholder meetings on an annual basis, primarily for the benefit of Shareholders in TopCo and third party observers to review progress and allow for knowledge transfer. For these two operating costs, the model allows USD265,000 annual budget for travel, accommodation, venue hire etc.

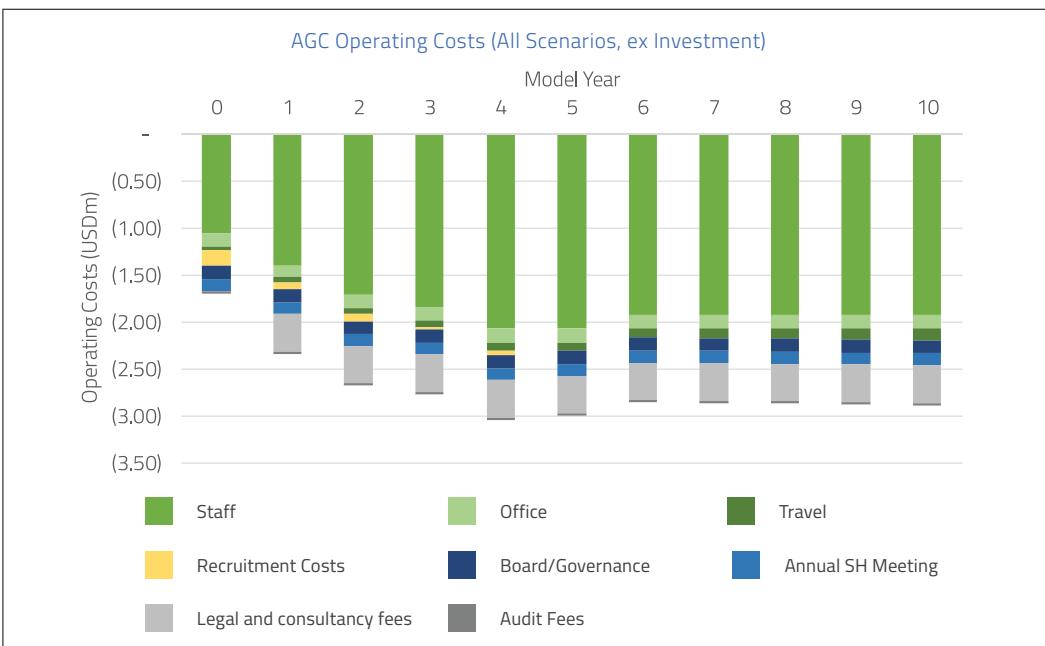
¹⁵ IT equipment for power trading – through subscriptions to software and trading platforms – is likely to take a substantial portion of this. However, the sensitivity analysis below describes the impact of operating costs on returns and as such this figure is reasonable.

¹⁶ For an overview of the proposed corporate structure for AGC, please refer to *Section 8.1 (Corporate Structure)* and *Annex 4 (Africa GreenCo Corporate Structure Governance and Regulatory Options)*.

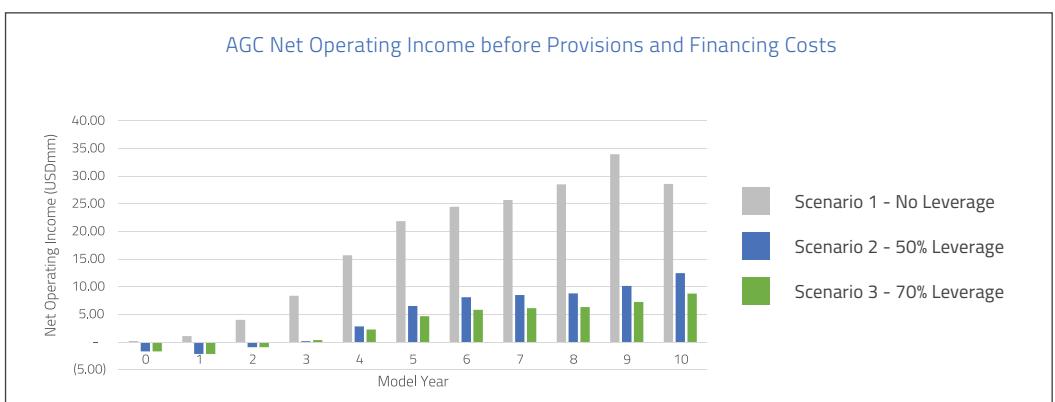


5.5.4. Total Operating Costs

Taken together, the core operating costs for AGC increase to USD3m per annum during the establishment of AGC and average USD2.8mm per annum in the following ratios:



Before accounting for provisioning, and financing costs, this means that AGC has a robust net operating income range of between USD10m and USD35m depending on the capitalisation¹⁷ and the resultant quantum of investment income.



¹⁷ For detailed discussion please see [Sections 5.10 \(Leverage\)](#) and [5.11.1 \(Investors\)](#) below.

5.6. Financing Strategy

This section of the Feasibility Study describes the key considerations relating to how AGC may be financed to implement the proposed operating model. Specifically this analysis reviews:

- ⌚ How much capital will AGC need in order to:
 - fund operating costs before the strategy becomes cash-flow positive;
 - have sufficient liquidity to enter into and deliver on trading and purchase/sale contracts; and
 - be perceived as a creditworthy offtaker.
- ⌚ Which sources of capital might AGC use in terms of:
 - The relationship between creditworthiness and leverage; and
 - Tranches of capital to accommodate investors with different risk/return expectations.

5.7. Development and Establishment Costs

The upfront costs involved in constituting the AGC entities are not included in the Feasibility Study, which addresses the ongoing operation costs of the proposed intermediary. Estimates for the development cost range from USD1.5m to USD5m depending on the resources used.

Excluding these costs is in line with comparable innovative finance strategies such as Africa50, the African Renewable Energy Fund, the PIDG Group, ATI and AGF for which the cost of consultants to develop the operating model, appoint management teams, create the legal entity and prepare other key documents were funded through grants by the donors which acted as “godparents” to these new vehicles.

5.8. Capital Requirement

Before we can begin to address how AGC will be funded, it's important to understand how much funding will be required. The main components of AGC's operating strategy that drive how much funding AGC will need can be split into the following categories:

- ▶ **Working capital and short term liquidity** for i) payments under PPAs and ii) deposit and other working capital requirements associated with trading power via a power pool;
- ▶ **Exposure to the termination value** payable to the Generator in the event AGC defaults under the PPA. The most probable cause of this would be an extended payment default by an Offtaker under a PSA and a consequent inability of AGC to secure an alternative purchaser for the power; and
- ▶ **Foreign exchange fluctuations** should AGC incur a mismatch between PPA/PSA currencies or receive PPA/PSA margins in hard currency but pay operating costs in local currency. As noted below this has not been included in assumptions under the base operating model, but *Section 5.9 (Foreign currency exchange risk)* below describes the key parameters of incorporating a currency component into AGC's strategy.

5.8.1. Working capital and short term liquidity

The working capital and short term liquidity component focuses on how much cash AGC will need to have on hand to i) pay for its day-to-day operating and contractual requirements and ii) have enough liquidity to give sufficient comfort to contractual counterparties (both in terms of traded power and long term PPAs/PSAs).

PPA Short Term Liquidity

In many cases for African and global PPA contracts, IPP investors require the offtaker to demonstrate sufficient funds to be able to meet monthly payment obligations. This security can take a variety of forms, notably:

- ⌚ An escrow account for collections from consumers;
- ⌚ A Letter of Credit from a creditworthy financial institution;
- ⌚ Standalone liquidity/debt facilities; or
- ⌚ Committed access to public budget/levies.

In both instances, African utilities are required to allocate capital as collateral for their payment obligations. An escrow account inherently requires 100% of the amount, but so do most Letters of Credit or equivalent third party security structures. The following approaches have been adopted for the existing sub-Saharan African IPPs:

Project	Country	Type	COD Year	ST Security Arrangement
Azito	Cote d'Ivoire	OCGT	2009	Escrow Account equivalent to 1 month capacity charge
All IPPs	Cote d'Ivoire	N/A	N/A	Legal right over budget
Takoradi II	Ghana	OCGT/CCGT	2000	USD3m Letter of Credit ¹⁸
Iberafrica	Kenya	MSD/HFO	1997	Initially advanced cash deposit payment
Kipevu II/ Tsavo	Kenya	MSD/HFO	2001	Escrow account equivalent to 1 month capacity charge Standby letter of credit equivalent to 3 month billing
Olkaria III	Kenya	Geothermal	2009	Standby letter of credit equivalent to 4 month of billing
Iberafrica II	Kenya	MSD/HFO	2000	Initially advanced cash deposit payment
Mumias	Kenya	Biomass	2009	Payment guarantee
Rabai	Kenya	MSD/HFO	2010	Standby letter of credit equivalent to 5 month capacity charge, 2 month fuel payments
Olkaria III	Kenya	Geothermal	2009	Escrow account equivalent to 1 month capacity charge Standby letter of credit equivalent to 3 month billing
Iberafrica III	Kenya	MSD/HFO	2009	Initially advanced cash deposit payment
Olkaria III	Kenya	Geothermal	2011	Escrow account equivalent to 1 month capacity charge Standby letter of credit equivalent to 4 month billing
Thika	Kenya	MSD/HFO	2011	Standby letter of credit with recourse to IDA PRG
Gulf Power	Kenya	MSD/HFO	2014	Standby letter of credit with recourse to IDA PRG
Triumph	Kenya	MSD/HFO	2015	Standby letter of credit with recourse to IDA PRG
Lake Turkana	Kenya	Wind	2016e	Letter of credit equivalent to 6 month capacity payment (USD54m) requested Escrow account capitalised by levy on tariffs
AES Barge	Nigeria	OCGT/CCGT	2001	Standby letter of credit
Azura	Nigeria	OCGT	2016e	Letter of credit from NBET with recourse to IBRD PRG
GTI Dakar	Senegal	OCGT/CCGT	2000	Escrow Account
Kounoune I	Senegal	MSD/HFO	2008	Letter of credit from SENELEC
Tobene	Senegal		2016e	IDA \$40m guarantee of SENELEC/GoS payments
Independent Power	Tanzania	MSD/HFO	2002	Liquidity facility equivalent to 5 month capacity charge
Songas-Songo Songo	Tanzania	CCGT	2004	Escrow account capitalised by fuel surcharge Liquidity facility equivalent to 4 month capacity charge for first 3 years; 2 month capacity charge from year 4
GET FiT	Uganda	RE	2012-	Letters of credit from GoU with recourse to IBRD PRG

These examples show a range of strategies for security arrangements. The typical amount is a one month escrow account and a one to six month letter of credit arrangement. Comparable initiatives in this space have used longer tenor security arrangements – so KfW's Regional Liquidity Support Facility being designed is exploring options for 6, 9 and 12 month LCs. Counter examples include Rwanda, where short term liquidity accounts are expressly forbidden – with the sovereign guarantee deemed adequate cover, despite taking 6 months to call on and involving significant legal processes.

In the feasibility analysis, the assumption is that for AGC to be viewed as sufficiently creditworthy, it must have 3 months' cash on hand to make PPA payments, and sufficient additional working capital (1 month) to support mismatched payable/receivable billing times – i.e. in line with the typical 3 month LC/1 month escrow account arrangement.

Requiring AGC to hold capital as security against its short term obligations may be unnecessary; as in the PTC example, AGC should be able to reduce its provisioning if:

- ④ The billing cycle is shortened to 1-2 weeks;
- ④ The PSA to the ultimate offtaker incorporates security structures; and/or
- ④ Investors have sufficient confidence in AGC's ability to enforce the PSA.

¹⁸ As a 220MW OCGT plant, the expected output on a monthly basis is in excess of USD10m.

The current assumption is that AGC will maintain its own 3 month liquidity provision and require liquidity provisions under PSAs in line with market norms. This approach is conservative and it may be possible for AGC to provision less capital on the basis of the PSA's requirements on the offtaker for a reserve account/Letter of Credit. If the market begins to accept lower provisioning, AGC will seek to reduce its own allocation and that of the PSA counterparties – or remove one or both entirely.

Within most trading markets, participants must also provide security against transactions. For short term trading in the SAPP, the requirement quoted in the Book of Rules for the Day-Ahead Market prepared in 2009 is:

(i)	A security account at Stanbic Bank, Gaborone, Botswana;
(i)	One USD-denominated and one ZAR-denominated sub-account;
(i)	Cash deposit or guarantee from creditworthy local financial institution
(i)	Equivalent in value to last 13 days of transactions and transaction fees;
(i)	Can be withdrawn on 7 days' notice.



In terms of transaction settlement, SAPP has the following billing cycle under the DAM:

Day 1:	Prices are calculated and trading notifications issued;
Day 2:	Invoices are issued; traders must have sufficient security to issue the credit note against the invoice for each transaction;
Day 11:	Buyers make payment for transaction to the market operator;
Day 12:	The market operator makes payment to the Seller.

- ▶ For overdue payments, the market operator makes a claim against the buyer's Security Account;
- ▶ Interest on overdue payments is made at USD/ZAR prime rates.

On this basis, our assumption is that AGC will have cash equivalent to 1 month's trading volume to meet the 20 day security arrangement. In addition, we allow 0.5 month's working capital on hand in order to fit the billing cycle. As the monthly and weekly Forward Physical Markets develop in SAPP it is likely that trading transaction sizes will increase – and therefore it is likely that the security/working capital that AGC is required to commit will increase. Despite creating a liability for AGC, this security arrangement reduces risk – since other participants in the SAPP will have to meet the same requirement and therefore will be sufficiently liquid to pay AGC promptly.

5.8.2. Termination Value

Fundamentally, AGC's largest financial exposure is the PPA termination liability. In any given period there is a theoretical risk of default by AGC on the PPA. The most likely trigger for an AGC payment default would be a payment default by multiple Offtakers under their PSAs followed by an inability of AGC to trade power elsewhere and/or delay in receiving termination compensation from Governments following Government default.

It should however be noted that it is highly unlikely that all of the projects would default at the same time and AGC would be unable to find alternative offtakers for any of them, assuming AGC builds a diversified portfolio of offtakers in a number of countries. Please refer to [Section 7.10 \(Credit Support Arrangements and AGC's Credit Mitigation Strategies\)](#) for a detailed analysis of AGC's credit mitigation strategies through which it seeks to preserve the PPA (and prevent a termination payment) arising even where an Offtaker defaults under its PSA. This separation of payment default risk and insulation of the Generator is one of the key benefits of AGC's structure. This becomes a factor in determining how the total exposure AGC incurs will be capitalised (below)

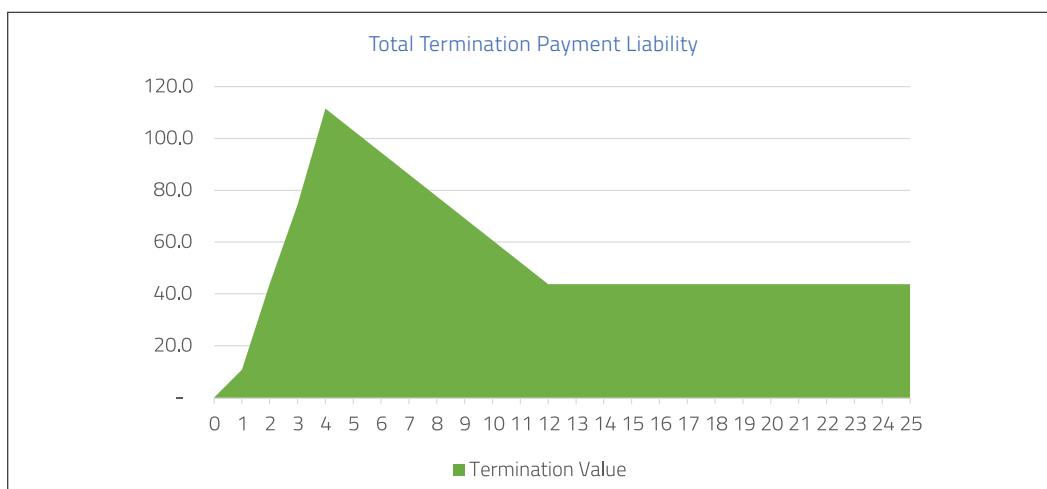
In the event an AGC default under a PPA arises, this would trigger a termination payment to the Generator. To calculate the termination value exposure, we reviewed methodologies active in the region. The principles of the

termination payment for AGC default are that it should compensate the lenders and equity investors as if the project had not terminated.

The assumed termination payment calculation for the Feasibility Study is as follows:

Termination Value	
Pre – Commercial operation date (COD)	<ul style="list-style-type: none"> ⦿ Outstanding Debt ⦿ Invested Equity ⦿ 20% returns on equity for greater of: <ul style="list-style-type: none"> ▪ The period from financial close to termination calculation date ▪ 2 years ⦿ Transaction Costs
Post – Commercial Operation Date (COD)	<ul style="list-style-type: none"> ⦿ Outstanding Debt ⦿ Invested Equity ⦿ 20% returns on equity for 2 years ⦿ Transaction Costs

The termination value for a single project using the methodology above produces the following profile for a sample 40MW hydro project in Zambia during construction (Y1-2) and the first 23 years of operation (Y3-25).

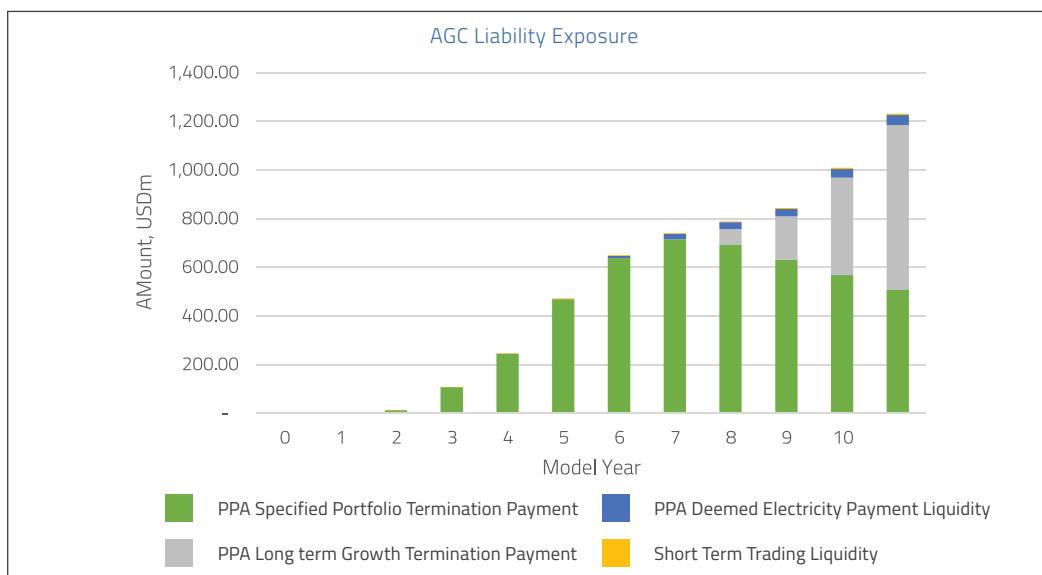


As the project portfolio matures the level of AGC's contingent liability vis-à-vis termination payments decreases over time for a single project. Initially, equity and debt investors have the most capital at risk invested in the IPP for which the termination payment would compensate them. The debt amortizes over the contract and therefore the termination payment tends towards the equity repayment plus short term forward looking returns and transaction costs.

However, assuming AGC's portfolio of exposures continues to grow, new projects with new, long term debt will continue to be added and the aggregate maximum potential liability of AGC for termination payments will continue to grow unless and until AGC decides to wind down the portfolio and stop entering into new PPAs.

5.8.3. Total Liability

The total liability exposure across the portfolio is the sum of the short term and long term liabilities/uses of capital associated with the AGC operating model.



5.9. Foreign currency exchange risk

While AGC's primary objective is mitigating the credit risk associated with contracting with financially weak national utility companies, this credit risk is closely linked to foreign currency exchange (FX) risks. Aside from a few notable exceptions, PPAs in sub-Saharan Africa are generally denominated in USD and the government provides protection to the Generator regarding the payment, convertibility and transferability of USD payments. Depreciation of a local currency against the USD, which often occurs in developing countries including most of sub-Saharan Africa, therefore results in a corresponding increase in the cost of electricity. Most IPP defaults across the developing world were precipitated by rapid depreciation of local currencies which led to unsustainably high USD denominated electricity tariff payments due from a utility whose income is founded on local currency retail tariffs.

- ▶ Most IPPs across Africa generate power under USD denominated power purchase agreements while collecting local currency tariffs from their customers.
- ▶ South Africa is the notable exception and has mandated Rand-denominated PPAs. This was facilitated by its mature and substantial local financial institutions as lenders, its market size and relatively low credit risk.
- ▶ In some countries (e.g. Rwanda, Ghana) payments are made in local currency but converted at the market-derived exchange rate against a fixed USD tariff.

Even in those instances where the FX risk is passed on to end-users by linking electricity tariffs to a USD index, the mismatch of USD-denominated power prices and local currency incomes can create severe economic and social stress. This risk has to be either absorbed by the utility, creating a (or exacerbating) significant credit risk, or by the general public. The political fall-out from unsustainably high customer tariffs can force governments to renegotiate existing power purchase agreements or risk public unrest.

In theory the credit risk challenge is mitigated by matching the currencies such that the IPP is paid in local currency – since each utility (and its sovereign implicit/explicit guarantor) has a lower credit risk profile in its domestic currency. However, the sources of capital (and expenditure requirements in terms of CAPEX) for most renewable energy IPPs are fundamentally hard currency denominated, stemming from international / cross-border contractors, equipment suppliers and investors, including DFIs. As such, few IPP developers and sponsors are actively seeking local currency tariffs.

AGC may consider being the intermediary between hard currency PPAs and local currency PSAs. However, creating a structure where AGC is able to address currency risk and benefit from this synergistic effect on its own credit risk is challenging. The section below describes the high level options and their implications.

AGC Options

The obvious response to these FX risks are local currency denominated PPAs. Related thereto, the question arises whether AGC can contribute to mitigating FX exposure in African electricity markets. There are two ways of mitigating systemic FX risk in the electricity sector:

Option 1: PPAs are (fully or initially partially) denominated in local currency up to the extent of local currency lending to the project (and depending on the return expectations of equity holders and the probability of attracting developers that will consider dividends in local currency);

Option 2: AGC purchases USD denominated power but on-sells to local utilities in local currency

In both instances, AGC is exposed to substantial foreign exchange risk:

1. Under Option 1 AGC is guaranteeing a (part) local currency cash flow stream backed by its USD denominated balance sheet; and
2. Under Option 2 it directly carries the risk of mismatch between USD purchases and USD sales.

As with AGC's potential role with respect to insurance and credit enhancement providers, AGC can also initially act as a passive intermediary/broker for currency solutions on a project-by-project basis with a longer term goal of transitioning into the two more active roles as AGC (and the market as a whole) develops.

Considerations for Active AGC Options

There are two main issues that an AGC effort to address the currency mismatch runs up against:

A limited demand from investors to lend in local currency to IPPs

The root of this currency mismatch is that IPPs generally require international capital to finance their construction and operation. Foreign investors are not generally willing to take local currency exposure and hence demand USD denominated PPAs.

Local investors have a growing appetite for larger, longer dated infrastructure projects, but limited capacity to support the number and range of deal types in the IPP pipeline across the continent and/or those that do have the appetite do not have access to long-term USD funds and as a result are frequently precluded from hard currency lending to IPPs. The AGC structure may therefore facilitate more lending by local institutions through:

- ◎ reducing the credit risk profile at IPP level; and
- ◎ introducing (partially) local currency denominated PPAs on the back of increased availability of such local debt funding.

It is unlikely to entirely dispense with hard currency denominated PPAs however as the quantum of capital required is beyond the local markets financial capacity, technical capacity and strategic priorities and key capex components such as equipment, technology and specialist construction contractors are likely to still be imported and priced in hard currency. This context will gradually improve, but AGC alone cannot catalyse local institutional capital engaging with long term infrastructure investment.

The cost and complexity of managing credit risk and currency risk simultaneously will impact AGC's financial viability

To intermediate credit risk, AGC is proposed to be set up with sufficient risk capital to meet its payment obligations under its PPAs even in the event of offtaker default. If AGC were to provide FX risk intermediation as well, it would have to source protection against movements in the FX markets. Theoretically, this can be done by entering in FX hedges with entities such as TCX and certain banks willing to operate in a specific currency (e.g. Standard Bank, Barclays, Ecobank etc.). FX hedging can be done through the purchase of options or entering into FX swaps. In practice, hedging large and long-term exposures arising under a typical PPA creates a range of issues:

- ◎ Long dated FX options are not widely available – and where they are will be expensive for AGC to take on.
- ◎ FX swaps create significant credit exposure between counterparties. Typically, cash collateral must be provided to cover such exposure, requiring significant additional liquidity. However, for long-dated

hedging of utility exposure, cash collateralisation is not an option and a guarantee structure must be considered, which would be compliant with regulations such as the European Market Infrastructure Regulation (EMIR).

- ⑤ Capacity constraints of hedging counterparties are substantial – even in more liquid markets a total notional amount of USD 50m over 10 years (roughly equivalent to a single 15MW PPA) is significant. A whole portfolio of exposures in line with AGC's ambitions will be beyond the current capacity of active hedging partners. TCX currently has a single currency net exposure limit of 10% of its primary swap portfolio and expects its portfolio to grow gradually to about 4 billion in the coming years. However, TCX is scalable. Additional risk capital would need to be found and TCX will work with commercial banks and institutional investors to deepen the swap markets.

The points are interdependent. Even as the local currency hedging market grows, other sectors will also seek to manage their foreign currency exposures more effectively and may rapidly absorb this capacity. If demand for such hedging instruments is higher than supply, the terms offered by hedging providers may become difficult for AGC to bear: they are likely to be short dated and/or create significant liquidity risk for AGC through their collateralisation requirements.

Recommendations and Feedback

The core recommendation on currency risk from stakeholders engaged as part of the preparation of the Feasibility Study was that tackling both credit and currency risk would be too broad a remit for AGC to successfully implement initially.

Moving towards (part) local currency PPAs should be an objective for most African countries. This will likely be a gradual process, given high local interest rate environments in many countries and local bank's limited capacity to provide long dated fixed rate financing¹⁹.

AGC is well placed to play an important role in this process; however, any FX intermediation by AGC needs to be looked at individually and may require additional financing and liquidity support to protect AGC's investment grade rating. Once AGC has established that it can address the wider credit risk issue, it should explore the option of layering on more sophisticated strategies to manage currency risk. In the interim, AGC can explore project-by-project opportunities to mitigate currency risk without AGC taking exposure – i.e. through partnerships with parallel initiatives that are explicitly designed to tackle local currency issues such as GuarantCo and TCX.

The financial analysis contained in this Feasibility Study therefore assumes that AGC is not taking any FX risk.

5.10. Leverage

5.10.1. Credit Rating

AGC's creditworthiness should aim to be verified through a credit rating. The earlier such rating can be obtained, even on an indicative basis, the easier it will be for potential investors in AGC to assess the business proposition. It may however not be possible to obtain a full rating until AGC has some trading history. In order to generate benefit, AGC should target a credit rating that allows it to be:

- ▶ At least as creditworthy as the highest rated underlying PSA offtaker. For AGC to create value, it must be deemed as a lower credit risk than any utility it sells power to – otherwise it will not have an impact on the cost of capital for IPPs by making more projects bankable. The highest rated sovereign is Botswana at A- (Standard and Poors). BPC's credit is likely to be at least two notches below this level – i.e. BBB.
- ▶ In line with comparable development finance credit enhancement strategies. The majority of strategies target an A range rating. ATI is rated A by S&P; GuarantCo is rated A1 by Moody's, AA- by Fitch and AAA for ECOWAS by Blomfield; Africa50 is targeting an A rating. The larger multilateral and regional development banks target AAA ratings to support borrowing in capital markets. For an entity like AGC this may be too restrictive in terms of the types of contracts and projects that AGC can support.

¹⁹ Given the fixed nature of payments under a PPA, financing power plants with floating rate debt can result in a cash short fall in the event that short term interest rates (which are the benchmark for floating rate debt pricing) spike. For example, in Kenya during Q4 2015, the 182 days Treasury Bill rate went from around 10% to 24%; floating rate debt service costs would have more than doubled during that period.

The factors driving AGC's relative creditworthiness include:

- ⌚ Leverage on financial exposure relative to equity capital base;
- ⌚ The underlying credit risk of PSA liabilities;
- ⌚ Ability to mitigate risks through strong back-to-back PSAs and ability to sell power to an alternative offtaker in case of default.

Until AGC's capacity to trade power is proven, the main focus will be on AGC's leverage and the underlying credit risk of the portfolio. The two are linked – in that AGC would have to have a higher equity base to cover losses from a higher risk portfolio. Long term credit default rates can be used to determine the level of equity required to back stop a portfolio of PPAs.

5.10.2. Portfolio credit risk

Two methods can be used to determine the equity requirement relative to portfolio credit risk:

- ⌚ Simple analysis taking long term default rates and recovery rates versus the level of exposure to each different credit risk.
- ⌚ Monte Carlo probabilistic analysis to get a more detailed sense of the underlying portfolio credit performance over time and that factors in increased cross-default likelihood for projects in the same country.

As discussed above, AGC's risk associated with the termination value is partially driven by the credit profile of the offtake counterparties. While there are many factors that drive the credit of the offtaker, key components include:

- ⌚ The sovereign rating (especially the foreign currency rating for foreign currency debt service)
- ⌚ The regulatory regime of the offtaker including regulations pertaining to power transmission
- ⌚ The historical and forward-looking financial performance of the offtaker (i.e. track record)
- ⌚ Nature of the offtaker, and their susceptibility to changes in economic activity, for instance, commodity cycles
- ⌚ The relative independence of the offtaker from Government influence
- ⌚ The transparency of its treasury operations

Investors, rating agencies and insurers evaluate the overall project risk on a project by project basis. In rare cases, a project's risk is assessed to be lower (a higher credit rating) than sovereign. For example, DFIs as well as commercial banks will lend in hard currency at below the sovereign Eurobond rate, particularly where there is a physical asset that can act as partial security.

For renewable energy project finance, potential credit uplift above the sovereign risk profile varies by project context. Technology, for example, has a major impact. Small scale solar, wind or biomass gasification/anaerobic digester systems have value independent of the project, since the equipment can be taken to a new location and re-used. For larger scale hydroelectric or geothermal projects, this option does not exist. Other factors include the developer and EPC contractor experience, the leverage of the investor base to mitigate risks and any explicit credit enhancement on the project.

5.10.3. Default Rates

Only one sub-Saharan African utility has a credit rating (Eskom in South Africa), though Malawi and Uganda have both been exploring (private/shadow) rating options and KPLC has a private rating for its locally placed KES debt. In the absence of utility specific ratings, the sovereign rate acts as a suitable benchmark for default rates. The long term hard currency default rates for each rating level are estimated in Table 11 below.

Table 11: Long Term Hard Currency Sovereign Default Rates for Rating Bands

Sovereign FC Cumulative Default Rates (1975-2011)										
Year	1	2	3	4	5	6	7	8	9	10
AAA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
AA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
BBB	0.0%	0.4%	1.3%	2.3%	3.4%	4.6%	5.2%	5.2%	5.2%	5.2%
BB	0.6%	2.0%	3.1%	3.9%	5.3%	6.8%	8.5%	10.4%	11.1%	11.1%
B	1.7%	4.4%	6.1%	8.5%	10.7%	12.7%	15.1%	18.9%	21.3%	24.1%
CCC	36.4%	45.5%	56.4%	62.6%	68.8%	75.1%	83.4%	83.4%	83.4%	100.0%

The above table is preferable over local currency rates, since PPAs are denominated in USD outside South Africa. However, it is noteworthy that were AGC able to develop a partial local currency PSA/PPA, the underlying risk exposure of the portfolio would improve by around 50% on a BB/B rating using the comparable rates from Table 12 below.

Table 12: Long Term Local Currency Sovereign Default Rates for Rating Bands

Sovereign LC Cumulative Default Rates (1993-2011)										
Year	1	2	3	4	5	6	7	8	9	10
AAA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
A	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
BBB	0.00%	0.50%	1.06%	1.68%	2.37%	3.12%	3.94%	3.94%	3.94%	3.94%
BB	1.36%	2.90%	3.47%	3.47%	3.47%	3.47%	3.47%	4.76%	6.29%	6.29%
B	1.79%	2.31%	2.89%	3.59%	4.42%	5.40%	6.61%	8.20%	8.20%	10.98%
CCC	7.41%	11.27%	15.49%	20.19%	25.17%	30.93%	38.60%	38.60%	38.60%	38.60%

Despite the fact that the actual/estimated sovereign ratings are low, the historic rates of default for project finance / public private partnerships in Africa are extremely low – 2.90% in the long run by the Basel II definition. On a global basis, only the Middle East lower long term rate of default on project finance. However, this does not necessarily translate into lower risk, since:

- ④ The number of projects included is lower – so it's possible that this is not a reflection of the true long term default rate,
- ④ The types of projects that have been executed in Africa and the Middle East are lower risk. Capital constraints mean that only the most bankable projects have been implemented; in developed markets, where capital is more freely available and demand for infrastructure investment opportunities is higher, marginal projects are more likely to be implemented;
- ④ African and Middle Eastern projects have come to market more recently than counterparts in both developed and developing markets – so it's possible that the long term default rates are not fully captured.

Table 13: Regional Long Term Project Finance Default Rates

Regional Project Finance Cumulative Default Rates, Basel II (1990-2012)										
Year	1	2	3	4	5	6	7	8	9	10
Africa	0.58%	1.19%	1.92%	2.53%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Eastern Europe	1.26%	2.63%	3.74%	5.09%	5.93%	5.93%	5.93%	5.93%	5.93%	5.93%
Latin America	4.20%	7.96%	10.91%	12.91%	14.17%	14.53%	14.74%	14.99%	14.99%	14.99%
Middle East	0.40%	0.92%	1.29%	1.59%	1.97%	1.97%	1.97%	1.97%	1.97%	1.97%
North America	2.50%	5.05%	7.12%	8.58%	9.78%	10.55%	10.99%	11.11%	11.25%	11.32%
Oceania	2.04%	4.08%	5.88%	7.41%	8.66%	9.69%	10.00%	10.00%	10.00%	10.00%
South East Asia	2.52%	5.00%	7.01%	8.36%	9.65%	10.28%	10.77%	11.18%	11.18%	11.18%
Western Europe	1.08%	2.15%	3.06%	3.90%	4.53%	5.06%	5.36%	5.65%	5.72%	5.72%
Cumulative	1.65%	3.37%	4.81%	5.94%	6.85%	7.41%	7.74%	7.95%	8.02%	8.05%

In the sub-Saharan African power sector, only four long term IPPs (AES Barge Nigeria, IPTL and Symbion in Tanzania and reportedly, Kivuwatt in Rwanda have PPAs that had to go to arbitration. For IPTL the issue was that the developer changed the technical specifications of the plant from Slow Speed Diesel to Medium Speed Diesel design after the PPA had been signed. This increased the EPC costs and tariff for Tanesco. The arbitration has run since 1998 – with various defaults on capacity payments and disagreements over tariffs. The AES Barge transaction entailed increasing the installed capacity and changing the fuel of the IPP; arbitration focused on payment due for deficient availability, capacity payments in arrears, and a tax exemption certificate which was withheld by the government for the duration of the project. Current fuel supply issues and operating challenges mean that the project has “essentially been mothballed.” Even in these cases, the utility did ultimately offtake power from the project. In six other cases, the utility and IPP renegotiated contracts, typically due to high perceived availability payments/tariffs and to relax liquidity provisions (Songas). In 2016, Tanesco “put on hold” its relationship with Symbion over a 15 year PPA for 112MW gas powered plant signed in December 2015. The exact status of the contract is unclear, but it represents an important indication of the struggles in some countries. Kivuwatt’s arbitration issues did not relate to operations – rather they were linked to tax exemptions during construction. However, and importantly, no IPP in SSA has yet triggered the sovereign guarantee.

These analyses create benchmarks for estimating the probability of default under AGC’s long term exposures on the basis of the sovereign credit ratings.

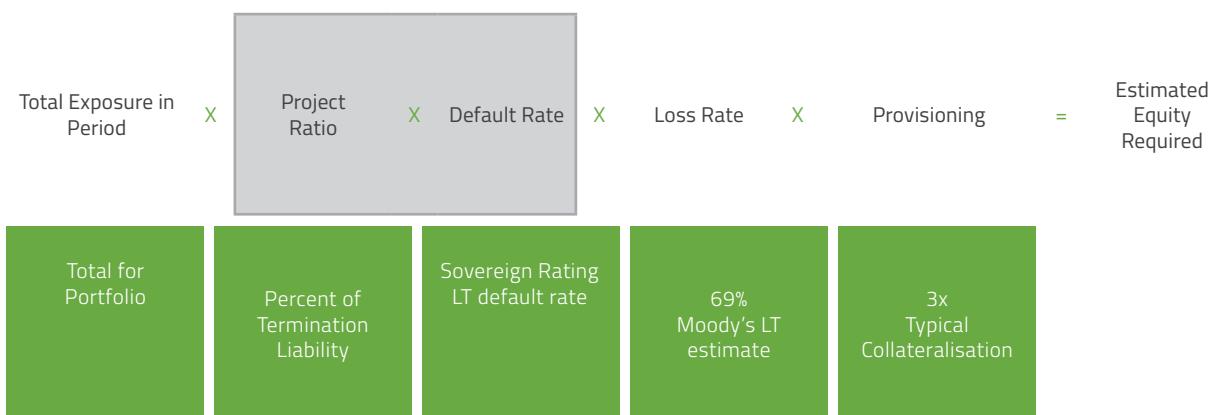
5.10.4. Recovery Rates

On default, not all capital is expected to be lost – in almost all instances there is partial compensation to the contracting counterparty. Moody’s estimated long term recovery rates on sovereign bonds from 1983-2011 is 31-36%; for the simple credit analysis model we have used 31%.

For the Monte Carlo model, recovery rates are set by years of non-payment; the model assumes 3 years of non-payment and reduced tariff thereafter. More importantly, the model factors the correlation between projects – i.e. if one contract in Zambia defaults, there is an increased likelihood that any other contracts in Zambia will also default.

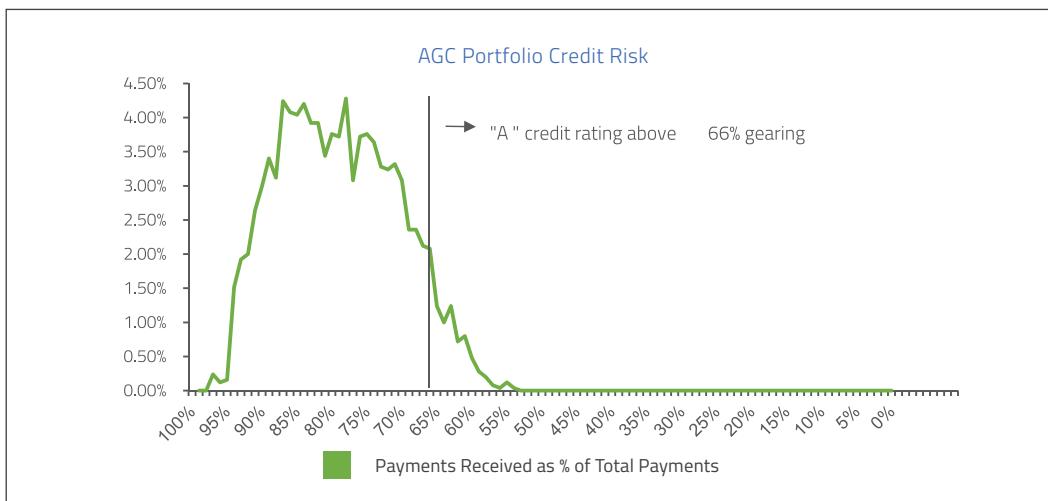
5.10.5. Leverage Calculations

The first level of analysis to assess the potential leverage that AGC could achieve is a simple estimate of the exposure relative to the long term risk of default for each project, calculated as:



The simple calculation method forecasts that on the basis of the hypothetical portfolio’s country exposures to termination payments, AGC can leverage its equity once over – i.e. it should aim to have 50% of its exposure in equity at any given time.

The second level of analysis used a stochastic Monte Carlo model that essentially tests the portfolio’s performance given the default rates over a number of iterations to generate a more nuanced picture of what the NPV of a set of termination liabilities due from a portfolio of utilities. Using the sovereign rating for the exposure credit risk of each PPA in the portfolio, the distribution of how that bundle of payments performs is as follows:

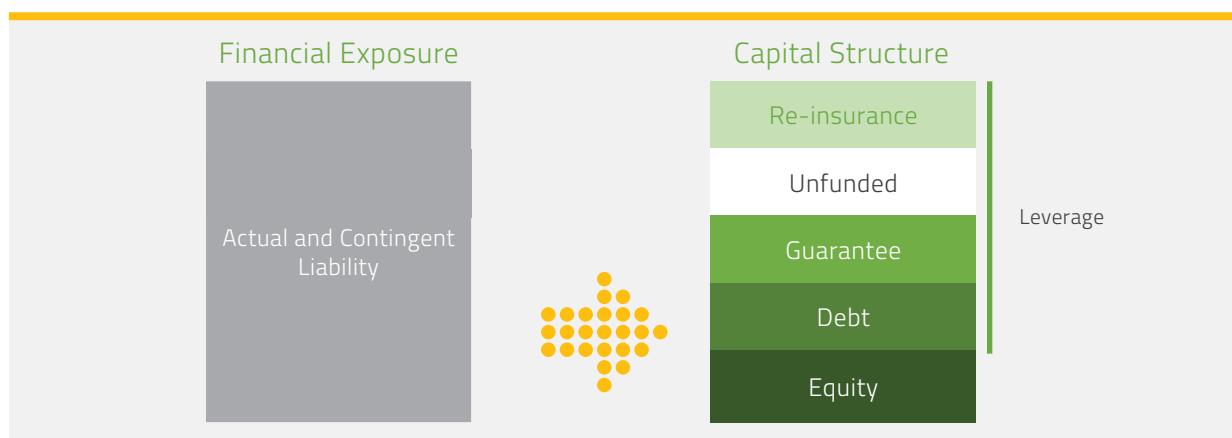


The model essentially finds that over 2,500 iterations of cash flows covering 25 years of obligations and given sovereign credit risk, the average repayment rate is 80% and at least 93.5% of the time the portfolio pays back more than 66% of its value. On this basis, AGC would need to have at least 33% equity to meet an A rating. Reducing the ratings by two notches to represent utility creditworthiness, the equity requirement increases to 35%.

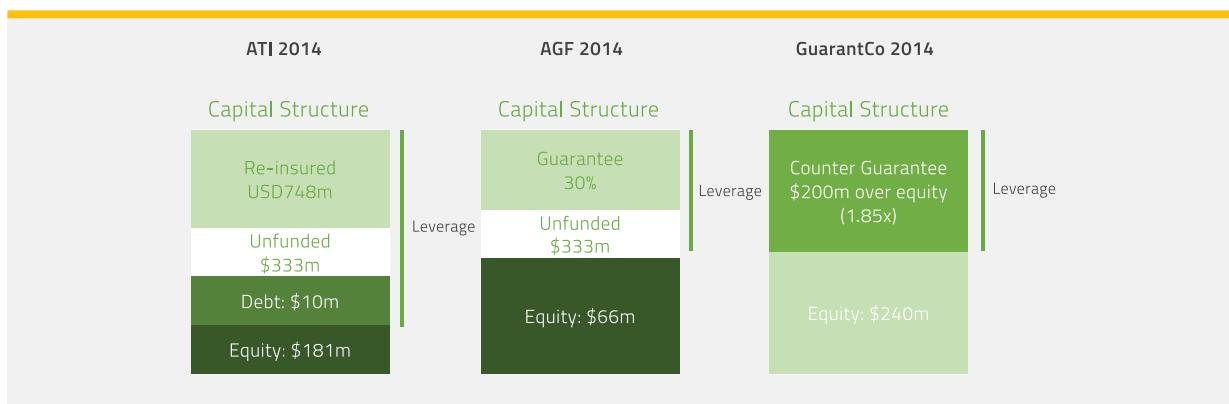
Taking an aggressive view on AGC's ability to sell power to alternative offtakers (i.e. reducing any default period to 1 year and recovery rate at the same value as the original PPA) has a pronounced effect – 90% of capital is recovered 93.5% of the time; AGC would only need a 10% equity cushion. 9x leverage is outside the realistic scope of creditworthiness; comparable entities such as ATI, AGF and GuarantCo reviewed below typically target 2-5x (i.e. 20-50% equity). The high level of repayment under a proactive trader scenario implies that the PTC India unfunded leverage model could be applied to AGC. However, PTC India i) has a more commercial approach, ii) only began acting as a long term PPA offtaker after 5-6 years of profitable power trading, and iii) had therefore built up substantial retained earnings to support these commitments. Feedback from IPP lenders active in sub-Saharan Africa was that an unfunded AGC would struggle to demonstrate sufficient creditworthiness to give investors the confidence to reduce their cost of capital.

5.10.6. Sources of Leverage

AGC's creditworthiness and ability to scale will depend on how much capital and in what form it requires and is able to raise relative to the size of this total contingent and actual liability exposure. For comparable innovative financing vehicles targeting risk mitigation, the core component of leverage are:



The following figures describe how different vehicles have incorporated each type of leverage into their capital structure:



Key components of how leverage is applied to development finance vehicles providing credit enhancement in practice are that:

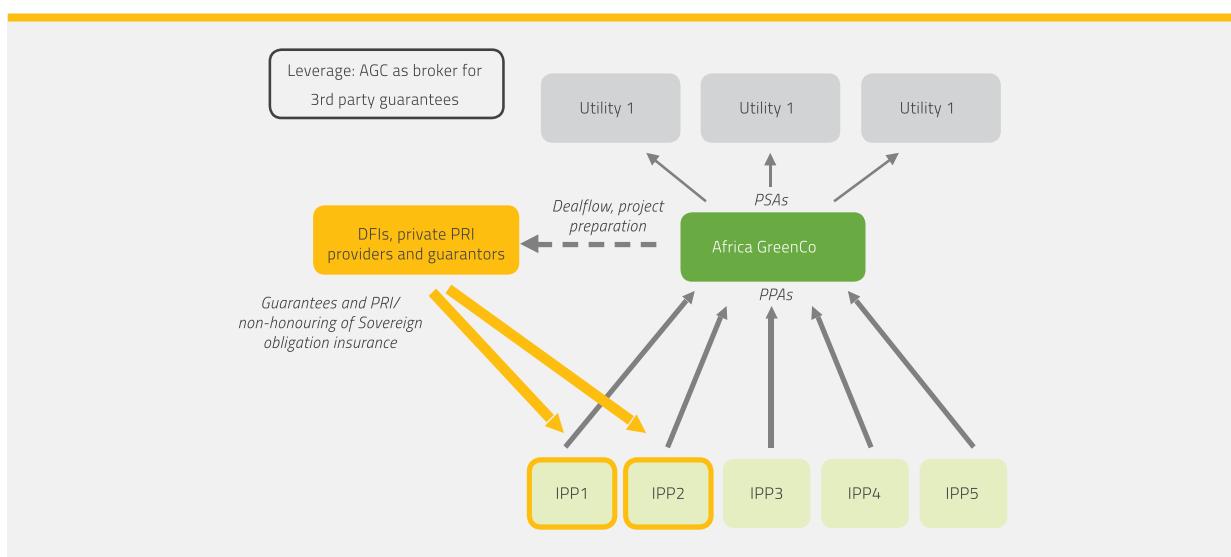
- ④ **Unfunded exposure** varies by entity but most target a long term ability to be able to take on exposures 2-5 times their equity.
 - For established entities like ATI with African sovereign shareholders, a diversified portfolio of insurance contracts and products and recourse to IDA allocations in case of default, the unfunded cap is 5 times the equity base (even if it is currently around two times).
 - AGF, which is both smaller and newer than ATI, has a much lower ratio (0.5) but expects to be able to achieve unfunded exposure of 3-4 times its net exposure over time;
 - GuarantCo's local currency guarantee portfolio is more concentrated in terms of the number of counterparties and takes on higher risk. Currently all commitments are fully funded. In the long run, it aims to be able to enter into 2-3 times its exposure unfunded.
 - PTC's long term PPA exposure is through offtake of 2,252MW installed capacity – with pipeline transactions under review for up to 12,000MW. PTC's capital base is USD400m equivalent – 10% paid in equity and 90% retained earnings and reserves. Termination payments associated with 2252MW power projects could be in the order of USD4bn – implying 90% of PTC's exposure is theoretically unfunded
 - PTC has demonstrated the ability to sell power through trading in case of default via IEX or bilateral contracts;
 - Typically contracts pass through all risk for capacity payments and termination payments the utility through the PSA
 - PTC has a track record of collecting payment on time from offtakers due to its option to sell elsewhere in case of default and its overhaul of the billing cycle.
 - PTC is a sufficiently profitable going concern with a diverse range of activities in the market and therefore should be able to make payment even in case of offtaker default or failure to find a market.
 - ⑤ **Passing risk to third parties** is a common strategy across most credit enhancement strategies. This takes the form of linking projects to guarantees and insurance products provided by other parties or by taking a guarantee directly on the portfolio of the entity.
 - For ATI, around 60%/USD750m of exposure is reinsured through third parties. ATI remains the primary insurer and therefore requires a minimum A- S&P rating or A AM rating for reinsurers;
 - AGF has re-guarantee contracts with SIDA for USD50m, ATI for USD8.5m and USAID's DCA for USD2.4m and will continue to re-guarantee its 30% of its portfolio exposure in a given period;
 - GuarantCo has a counter-guarantee on its portfolio provided by Barclays and KfW with support from FMO. This guarantee can take on up to two times the equity less 15% collateral against currency hedging (i.e. net 1.85x) to a limit of \$200m equity.

- ④ **Debt** is not a common approach to achieving leverage and increasing capacity – and where it is incorporated that debt is highly concessional, as in the case of ATI's \$10m IDA loan, provided with 25 year tenor as part of the Regional IDA support alongside government IDA loans for investment in ATI. PTC India has minimal debt (1%).

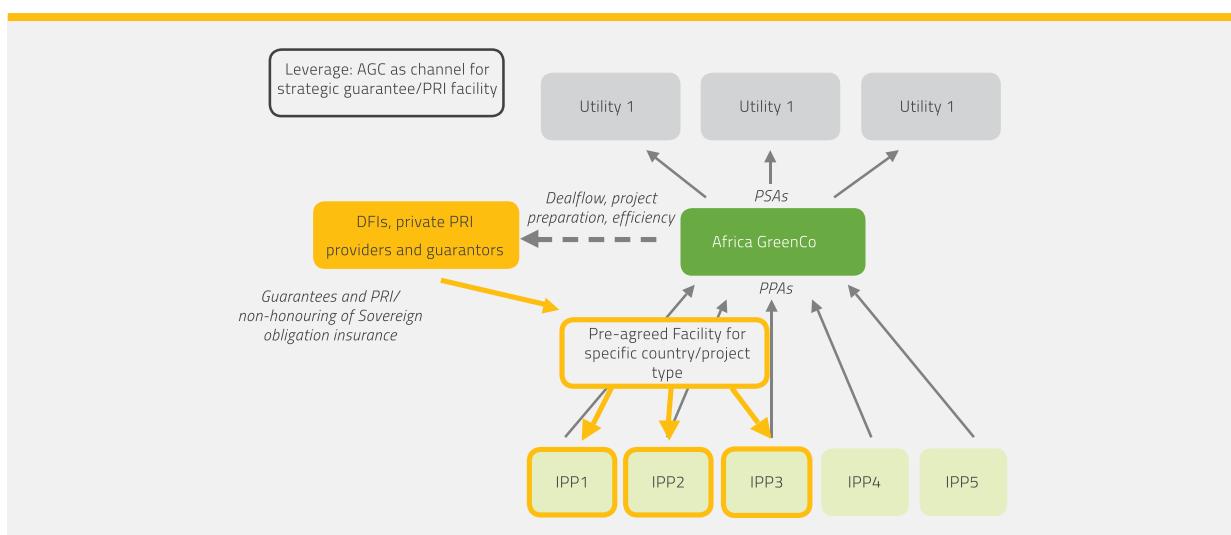
Taking these observations and applying them to the operating model of balancing long term PPA/PSA intermediation with short term trading, AGC should be in a strong position to increase the efficiency of any equity investment by passing risks to third parties through guarantees and reinsurance.

There are three basic models for how exposure could be transferred to third parties:

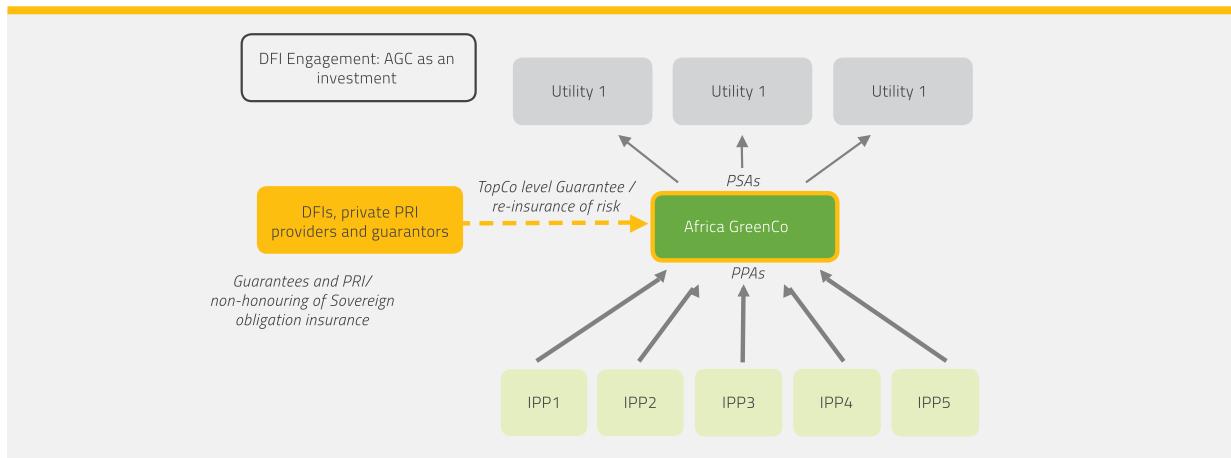
1. AGC acts as a broker between projects and credit enhancement providers willing to take on all/part of the offtaker risk; this would fit with current products offered by MIGA, IFC and GuarantCo as well as bilateral guarantors and may be the most appropriate strategy for AGC's initial transactions before it has built up a diversified portfolio. This would also allow AGC time to work with such guarantors to structure new products to mitigate AGC's risks on a more efficient portfolio basis.



1. Insurers or guarantors provide a facility to support a specific type of project in AGC's portfolio on a draw down basis, for example through country windows. This model has been implemented in the past under the World Bank's PRG scheme on a country-by-country basis in Nigeria, Kenya and Uganda. In these cases, the World Bank signed a high level PRG agreement that covered future investors in a portfolio of IPPs against delay in PPA payment.



3. AGC's portfolio as a whole is guaranteed or reinsured by third party DFIs or reinsurers, as per KfW and Barclays' support for GuarantCo, SIDA's support for AGF, the GHIF and CAFEF and the general observation that private guarantee and insurance resources institutions prefer portfolio level exposure with inherent risk diversification. Feedback from key insurers and re-insurers active in African power markets suggests that the level of appetite to work with an entity like AGC is high – with one regional organisation stating that as much as 95% of the offtaker risk that AGC takes on could be re-insured. However, this appetite may not be adequate given country and region specific limits and other strategic constraints relating to working with a new entity.



The most efficient structure from a transaction structure (and likely pricing) perspective would be to enable re-insurance at the AGC TopCo level. This approach creates a large, diversified, single commercially viable pool of risk that can be transferred. However, in recognition that AGC is a new model, and that existing credit enhancement and insurance providers are currently operating at a project level, it is likely that AGC will have to coordinate with these re-insurers on a project-by-project basis initially – with the longer term goal of creating new products which operate at a portfolio level.

5.10.7. Cost of Leverage

Each different type of leverage has its own cost estimates, described in more detail below. For unfunded exposure, there is no cost – the risk is being taken directly by AGC and therefore does not incur any fees.

For re-insurance and guarantee/re-guarantee products, the costs vary depending on the counter party involved. Data points on pricings for insurance products include:

Entity	Instrument	Upfront Fee	Ongoing Fee
IDA	PRG		75 bps
IBRD	PRG – up to 12 years	65bps	50 bps
	PRG – 12-15 years	65bps	60 bps
	PRG – over 15 years	65bps	70 bps
MIGA	PRI	0	50-175 bps
IFC	PRI for convertibility, FX risk	0	50 bps uncalled LIBOR+200bps
	Trade insurance (GTFP)	0	70-300 bps
AfDB	ADF PRG	10 bps	70 bps
	AfDB PRG	10bps	60 bps
MIGA	PRI	0	50-175 bps
OPIC	PRI	0	200 bps
ATI	PRI	N/A	100-350 bps
SIDA	Guarantee		0-500bps ²⁰
Private	Guarantee/PRI		100-500 bps ²¹

²⁰ SIDA Guarantees are priced according to the beneficiary and objective of the underlying project. For GHIF, no fee is incurred for the first loss and subsequent pari passu guarantee to investors no charge was applied – the purpose of the guarantee was to attract investors to an innovative and concessional strategy. For SIDA's guarantee to the Maputo Port project, however, which is commercial, the premium was between 3% and 5%.

²¹ Private sector guarantee/re-insurance fees vary widely as products range in terms of country/sector and can be tailored to a narrow set of risks. This is an indicative range of fees incurred through a guarantee product based on feedback from market participants.

For debt, the cost will be driven by local credit assessment on the part of the lender. If AGC is able to achieve an A range rating as per the discussion above, the approximate long term borrowing rate for hard currency debt in today's market is 6.5%.

For the prospects of raising debt, it is important to be clear on the investment proposition in AGC. As with many development finance vehicles, this involves a long-term strategic and low return investment to create a market. However, the financial performance of AGC in terms of key criteria such as return on assets, interest coverage, and short- and medium term profitability will not necessarily meet lenders' credit requirements. Debt also creates a cost in that the principal must be returned to lenders. The repayment – if amortized on a straight line basis each period – erodes AGC's capital base and therefore its creditworthiness and ability to back stop contractual exposure to investors. If principal repayment is paid at the end of the loan tenor, this creates refinancing risk for AGC – if it is not able to raise new debt, its position relative to contractual obligations may be untenable.

It may be for this reason that most credit enhancement strategies active in the African infrastructure markets tend not to access debt except in small increment and with concessional terms –in the form of both a long tenor (e.g. 25-35 year IDA loan or 10-15 year 2% donor loan) and low interest rate.

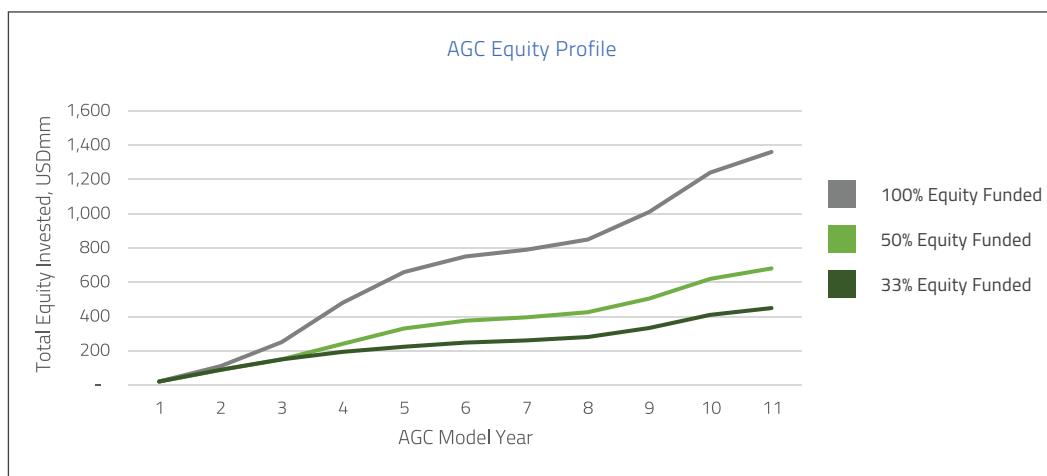
5.11. Equity

The total equity required by AGC to execute the business plan described above is a function of how much leverage AGC is able to achieve. On the basis of the credit analysis above, AGC requires somewhere between 30% and 50% equity relative to its portfolio risk in the medium term with the balance leveraged through guarantees. Once established, AGC should be able to take on additional unfunded risk. Using these parameters, there are three options for the capital structure:

Scenario 1:	100% Equity Y1-10
Scenario 2:	Long term: 50% Equity, 50% guarantee Y1-10
Scenario 3:	Long term: 33% Equity, 67% guarantee Y1-10

All scenarios for the capital structure envisage raising capital two years in advance of AGC's exposure, given the period involved in negotiating and signing transactions. AGC will need to demonstrate that it has the capital to back up its commitments to be a credible contract counterparty in negotiation (pre-construction).

The total equity requirement for each of these strategies is as follows:



The calculation for the equity contribution is as follows:

- ⌚ Total provisioning required for PPA liquidity;
- ⌚ Total provisioning required for short term trading liquidity;
- ⌚ 100/50/30% provisioning for PPA termination payment exposure.

It is unlikely that an IPP will commit to a long term PPA with an entity that has yet to raise the adequate funding to back stop the liability created by the contract. Therefore, the timing for when AGC should have sufficient capital to cover termination payment exposure is brought forward by two years, to allow AGC to enter into negotiations with an IPP on a firm financial standing. To the extent funding is committed by creditworthy institutions (such as the World Bank or KfW), it may not be necessary for the funds to be paid in so far in advance, and it may be possible to structure the shareholding arrangement such that the majority of investment from these high credit investors is callable – allowing AGC to backstop its liabilities, and increasing the capital efficiency for investors.

It should be noted, however, that AGC is capital intensive - even the minimum leverage scenario here – whereby AGC would only need equity to cover 33% of its exposure – the capital requirement is USD 449m to support a portfolio of 605MW installed capacity.

5.11.1. Investors

The final element of the capitalization analysis describes options for possible sources of equity. The basic assumption is that there are five different types of investor that AGC can target:

- ▶ African governments seeking (or being required) to participate in order to have skin in the game and play a direct role in driving and owning the AGC concept;
- ▶ Donors/equivalent grant and concessional capital providers seeking to catalyse private sector investment in the African power sector;
- ▶ DFIs active in African power sector looking to promote innovative, market-based solutions for improving the environment for commercial investment and risk mitigation;
- ▶ Impact investors and philanthropic organisations (e.g. Foundations, NGOs) seeking to contribute to developmental impact through mission-related investment;
- ▶ Strategic commercial capital, institutional investors and venture capital investors seeking market rates of return.

African Governments

Part of the motivation for AGC is that African investors, whether public or private, have become large and credible possible solutions to infrastructure needs. In particular, tapping such resources gives African institutions greater discretion and ownership over spending and freedom from the conditionality imposed by the development community. This capital can come from a range of sources depending on how governments want to participate:

- | | |
|--|--|
| ◎ Budget allocations
◎ Central Reserves | ◎ Sovereign Wealth Funds
◎ Public Sector Pensions |
|--|--|

The fiscal resources of African Countries are tightly squeezed, especially in current lower-growth and high volatility markets. Providing capital from central budgets for a regional financing vehicle will be a low priority for many governments:

- ▶ Low income countries have a low tax base and depend on budget support from donors.
- ▶ Low income countries have a low tax base and depend on budget support from donors.
- ▶ DFIs active in African power sector looking to promote innovative, market-based solutions to improving the environment for commercial investment and risk mitigation.
- ▶ Middle income countries such as South Africa have a larger revenue base, but face budgetary needs around recurrent spending and protecting their credit rating.
- ▶ All countries have their own infrastructure investment priorities and participation in regional mega-projects.
- ▶ Most countries are shareholders in national and regional development banks, which themselves are under-capitalized.

However:

- ▶ Governments stand to make direct financial benefit from the existence of AGC in terms of reduced power costs and lower contingent liabilities; and indirect impacts most prominently the higher tax revenues from increased economic productivity.
- ▶ Several countries have amassed sovereign wealth and foreign exchange reserves in relation to the export of natural resource commodities. Therefore, fund raising from African countries might be targeted at selected middle income and resource exporting economies – notably Botswana, Mozambique, and Zambia. However, the recent commodity cycle downturn has reduced the capacity for these countries to invest externally – politically, they must use their resources to partially mitigate macro-economic issues.
- ▶ General support for financing strategies has increased as governments recognize the domestic and regional value of taking new approaches to solve the substantial infrastructure funding gap.
- ▶ Various innovative finance vehicle have been funded directly by governments by tapping Sovereign Wealth Fund and Central Bank reserve contributions as well as direct investment from national budgets e.g. Africa50, AFC. For these entities the investment returns are close to commercial – in that the strategies of the entities is to build a portfolio of debt/equity investment on market terms.

Countries have historically also taken equity positions directly linked to their International Development Association (IDA) and/or African Development Fund (ADF) borrowings, as is the case with ATI. There may be scope to use the regional ADF and IDA envelopes to support AGC given its cross-border operations and ambition to raise capital from multiple African governments at the TopCo level. For a summary of IDA and ADF, please refer to *Section 7 (Ability to attract development funding and access support windows)* of *Annex 4 (Africa GreenCo Corporate Structure, Regulatory and Governance Options)*. Regional IDA is considered further below.

Regional IDA

A program for funding regional projects and initiatives using IDA loans to sovereigns was introduced at the 13th IDA replenishment in 2002 with USD435m allocation and has since grown to over USD3bn by 2016. The Regional IDA program has been implemented hand in hand with a growing recognition of the value of regional integration and coordination by Africa IDA-eligible countries to tackle large scale investment in infrastructure and other public goods. The criteria for Regional IDA are under review, but as they stand today to be eligible for support under the IDA's regional program, initiatives must:

- a. Involve three or more countries, all of which need to participate for the project's objectives to be achievable and at least one of which is an IDA country. The required minimum number of countries is reduced from three to two if at least one IDA Fragile and conflict Affected State participates in the regional project;
- b. Have benefits that spill over country boundaries (e.g., generate positive externalities or mitigate negative ones across countries);
- c. Have clear evidence of country or regional ownership (e.g., by ECOWAS or SADC) which demonstrates commitment of the majority of participating countries; and
- d. Provide a platform for a high level of policy harmonization between countries and be part of a well-developed and broadly-supported regional strategy.

In addition to the regional project eligibility criteria described above, two additional criteria are applied to prioritize projects, including

1. Regional projects should avoid funding primarily national-level investments with regional resources. The specific investments proposed within a regional project should have clear externalities, not just the regional concept itself; and
2. Given the high demand for IDA regional project financing, IDA funding should be considered only once other options have been ruled out. Leveraging other resources and working with development partners are strongly encouraged.

Funding must be matched by sovereign IDA investment –Regional IDA can account for 2/3 of the total cost

and 1/3 from the country envelope of each participating country. That sovereign contribution cannot be more than 20% of the national IDA allocation. Projects are funded on the same terms as those applicable to participating IDA countries.

Africa has been the main region for implementing Regional IDA, accounting for 94% of total expenditures up to IDA16. Sectorally, the focus is on regional infrastructure, economic integration through trade and market development, and public good promotion in terms of public resource use, agricultural development, regional health initiatives and education.

The Regional IDA program works within the context of regional institutions – and most directly support projects being implemented by these institutions. In Africa, the institutional architecture includes:

- the African Union and NEPAD at the regional level
- eight Regional Economic Communities,
- regional banks, and
- specialized technical bodies related to water resource management, power generation,

Financing can take one of the three forms:

- through the Institutional Development Fund (IDF),
- mobilizing grant co-financing alongside other donors;
- on-grants/loans by participating countries as part of their IDA financing

While the IDA Regional program can make direct allocations to regional bodies, in practice it only rarely works directly with these organisations – for example ATI, BOAD and BEAC. The reasons for this limited direct support identified by the World Bank include:

- **legal status of the entity:** some regional bodies do not have a legal status and therefore cannot enter into contractual arrangements directly, while others may lack the legal capacity to borrow, on-lend and repay a credit. Others lack an adequate and sustainable governance and financial structure to implement their activities under the program without a financial guarantee from the participating countries;
- **political considerations:** the participating countries may prefer to borrow directly and then provide some of the proceeds of the credit to the regional entity, in order to maintain control of the IDA resources and have the ability to reallocate these proceeds to national activities if activities at the regional level do not materialize
- **nature of the program:** some regional entities may include, as members, countries that are not participating in or are not beneficiaries of the IDA program, which may go against a desire to ensure that the full benefit of the credit's concessionality is accorded to the member country concerned.

The African regional power pools in general and Southern African Power Pool in particular have been one of the prominent recipients of Regional IDA support. From 2004 to 2009, SAPP received \$750m commitment for four underlying tranches of funding; three of these related to constructing/rehabilitating the transmission lines from the Inga dam project in DRC to link to Zambia; the fourth was to finance transmission lines linking Mozambique and Malawi. The West African Power Pool received \$260m up to 2010 for two discrete projects – the rehabilitation of the Felou dam to provide cross-border power to Senegal, Mauritania and Mali and coastal transmission line construction to connect Liberia, Cote d'Ivoire, Ghana, Nigeria, Benin and Togo.

Finding a way to work with the Regional IDA program is priority for AGC as a potential mechanism to facilitate local government investment, following the precedent of ATI. AGC's fit with Regional IDA covers both strategic and technical eligibility:

**Strategic**

AGC is aligned with the IDA Regional / Africa RIAS objectives in that it directly promotes cross-border power trade and clean energy development and supports stronger regional economic cooperation and institutions.

**Technical**

AGC will be established as an independent company and therefore will be able to enter into financial agreements. While countries may prefer to borrow directly, the total sum across a portfolio is relatively modest – USD80-200m – in line with historic project levels²². The nature of any program focused on IPPs and cross-border power trading in SAPP will inherently entail working with non-IDA countries such as Botswana, Namibia and South Africa.

For AGC, the value of creating a capital structure that accommodates African sovereigns lies in:

- Ensuring African political and financial ownership of the concept;
- Integrating AGC with existing national and regional infrastructure investment strategies;
- Raising long term contributions with lower financial thresholds in terms of return, risk appetite and exit strategy; and
- Aligning interests by creating a disincentive for sovereign-level default on PSA obligations in that the shareholding in AGC would be diminished as a result – i.e. governments would have “skin in the game.” As noted in *Section 7.10 (Credit Support Arrangements and AGC’s Credit Mitigation Strategies)* specific terms around how African government capital is incorporated can provide additional credit mitigation for AGC in case of default of a national utility of the relevant State. ATI’s approach to this is discussed in more detail below.

Donor Governments

Donor governments such as the UK, USA, France, Norway, Sweden, and Germany have prioritized low carbon development as part of their commitment under COP15 and have historically played a critical role in pioneering innovative finance strategies. In relation to African countries, the long-dated nature and public policy considerations involved in power sector investment means that there is naturally a role for donor grant / concessional funding. Development partners are committed to promoting infrastructure development through technical assistance and DFIs. As demonstrated by the PIDG umbrella facility and the Green Climate Fund, many of these donors are able to respond innovatively to the specific needs of a sector or thematic issues facing the region.

The tension that needs to be managed is to ensure the conditionality of any contributions does not limit the operational and financial flexibility of AGC.

While Donors invest through many of the above mentioned vehicles, one structure is particularly successful in attracting donor capital: structured finance institutions that incorporate donor funding as returnable capital (as opposed to grant contributions) alongside local and international public and private investors. These vehicles tend to raise capital for “strategic” purposes, i.e. for some wider collective benefit rather than financial return. Co-investors include governments and development entities but also some private financial institutions. Donors who have strategic alignment with AGC include:

- ▶ The UK/DFID is pursuing a range of innovative finance strategies that incorporate returnable capital and has sector specific interest in low carbon development and the Southern African region.
- ▶ USAID’s Power Africa initiative has demonstrated American commitment to the power sector, and in terms of the instrument, the Development Credit Authority (DCA) has been a pioneer in catalysing private capital through credit enhancement.
- ▶ The German Government through KfW are also focused on using grants to support and promote renewable energy in Africa, specifically through programs such as GETFit, GCPF and similar; In addition, KfW has been exploring credit enhancement for IPP PPAs against the short term liquidity provisioning requirement through the Regional Liquidity Support Facility.
- ▶ The Swedish government through SIDA has been executing innovative guarantee/credit enhancement transactions and can provide guarantees to new, multi-stakeholder entities.

²² Any allocation to AGC could be shared by 7 or more countries; the per country allocation ranges from 6-50% on a pro-rata basis equating to USD4-100m or USD11-30m on a pari passu basis.

Development Finance Institutions

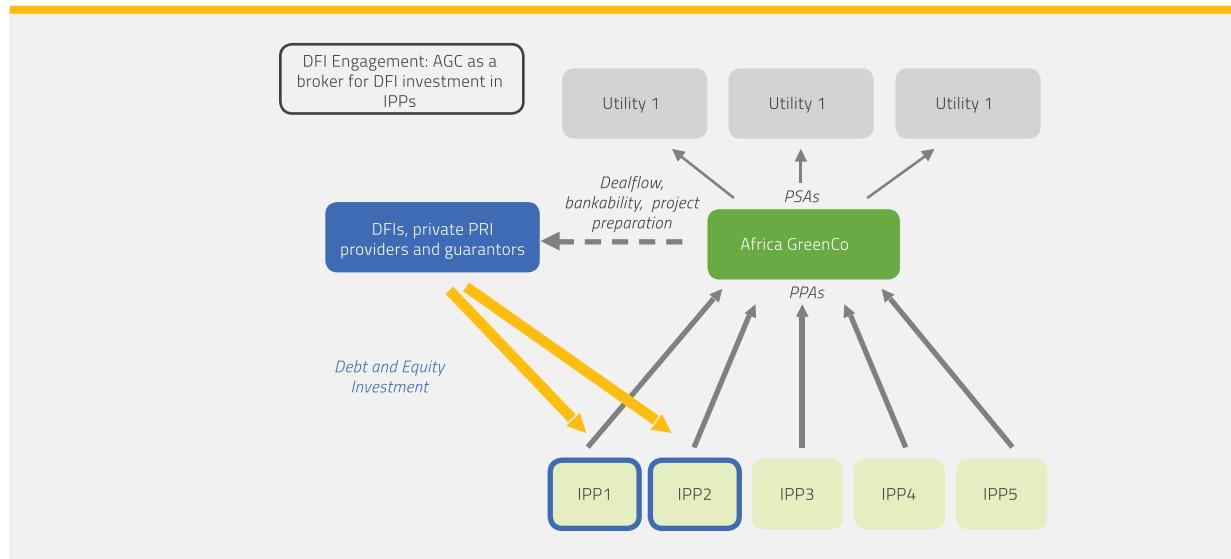
Development Finance Institutions (DFIs) are a key component of African power sector investment. The universe of DFIs can be characterized as follows:

- ④ Established Multilaterals with activities in Africa, e.g. the World Bank Group, the African Development Bank and EIB;
- ④ Regional Development Banks, funds and equivalents, for example the EADB, DBSA and EBID and associated regional infrastructure investment funds;
- ④ Sector specific development banks, funds and other strategies including the Private Infrastructure Development Group (PIDG) vehicles, the Green Climate Fund, the Climate Investment Funds; Sustainable Energy For Africa Trust Fund; and
- ④ Bilateral investment vehicles, including the main donor-funded DFIs (OPIC, CDC, Norfund, Swedfund, Proparco, FMO, KfW/DEG [as investors rather than grant providers]).

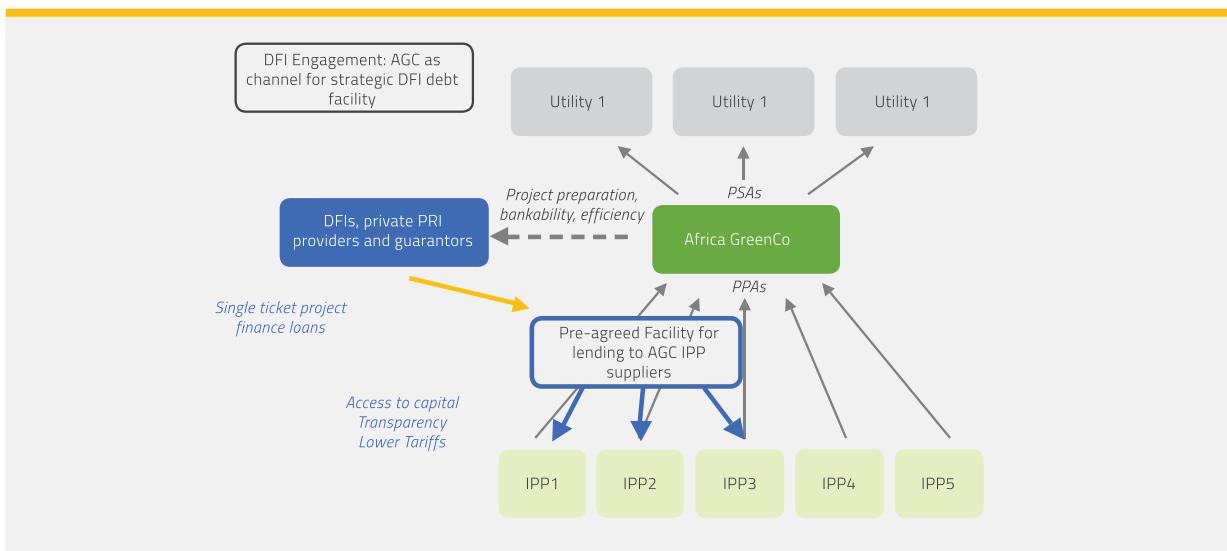
For AGC, the combined objectives of catalysing private sector investment in IPPs, supporting the growth of regional power markets and promoting renewable energy technologies are all shared with almost all DFIs. Provided the financial terms are a fit with DFI investment requirements, AGC should be an attractive opportunity.

Collaboration with DFIs could take a number of forms. In much the same ways as the potential for leverage described above, there are three main channels for DFI engagement with AGC depending on the instruments available to the DFI and its strategic objectives.

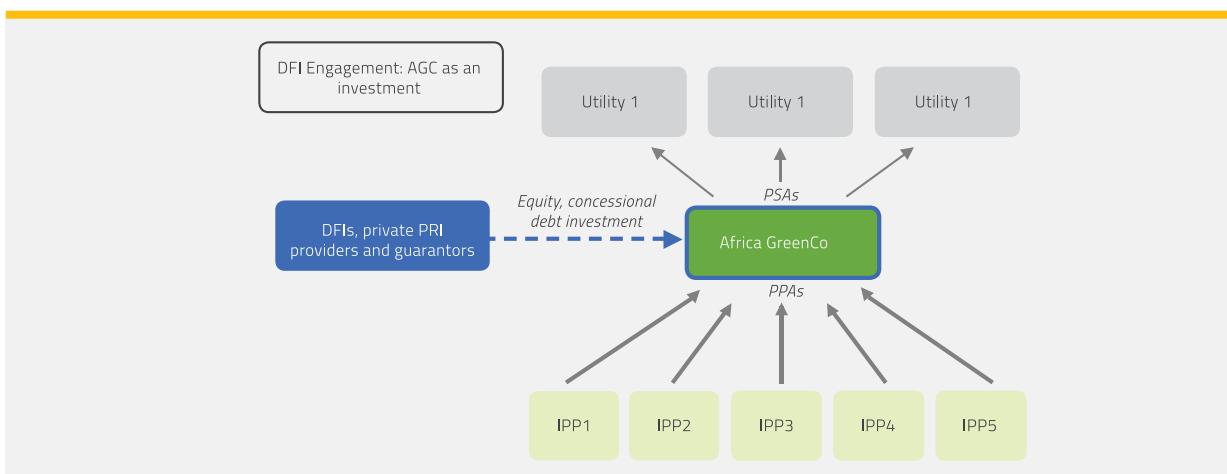
- 1. Broker role:** Under this scenario, AGC is able to support IPPs and link them to DFI products – whether in the form of early stage development capital, debt and equity at financial close or guarantee and PRI products. AGC benefits by helping to get more transactions over the line; the DFI benefits through increased deal flow and more bankable transactions.



- 2. Intermediary role:** Under this scenario, AGC acts as a channel for DFI capital into IPPs. AGC creates a multilateral debt or equity facility specifically earmarked for projects contracting with AGC. DFIs invest on their own terms into that facility; AGC consolidates the capital and on-lends / invests in IPPs at a blended rate. This model has been successfully adopted by MASEN in Morocco. MASEN consolidates concessional loans provided by the Clean Technology Fund (CTF), African Development Bank (AfDB), the World Bank (WB), and the European Investment Bank (EIB) which reduce the cost of capital for the IPP, and lower the overall cost of energy generated. MASEN blends the terms of the DFI loans and offers a single financing package as part of the development and bidding process. Critically this ensures adequate financing to the IPP, and transparency to equity investors as part of the tender process.



- 3. Investment role:** DFIs can directly invest in AGC in order to support market development, have direct visibility on regional power trading and generate financial returns.



- 4. Risk mitigation role:** as per the leverage section above, DFIs can use instruments to reduce AGC's risk – and therefore how much capital it needs to operate. DFIs can (partially) guarantee or insure AGC's payment to IPPs or Offtaker payments to AGC – either way, AGC would not need to provision as much capital against that net reduced contingent liability.

As with the risk transfer models above, the ideal scenario for AGC engagement with DFIs is through support and investment at TopCo level.

Commercial Investors

African commercial banks have been under-represented in funding infrastructure to date, given their limited access to long-term funding. Much like Central Banks, commercial banks hold substantial proportions of their assets in treasury bills and government bonds, central bank deposits or cash positions (around 30%-35%, according to Lion's Head research).

South Africa is again the exception, where the recent renewables programs have been extensively funded from domestic local currency resources. Nigerian banks have also participated heavily in the privatization of the power sector, although these loans are not generally beyond seven years and will need to be refinanced.

The question is whether some of the better capitalized African banks, particularly in South Africa, can invest in AGC. Nigerian banks are shareholders in AFC, partly driven by a strategic desire to increase infrastructure investment. Commercial bank shareholding in DFIs is common in Europe.

Some major African commercial banks may take a strategic view on investing in AGC, particularly if it enables them to increase their pan-African IPP lending. However, they are only likely to invest on this basis alongside major partners such as the AfDB and governments to ensure that AGC has political buy-in and complementarity with the major players in African infrastructure finance.

AGC's ability to tap into commercial capital will be critical to its long term success – as proven by PTC India. An initial limiting factor on AGC's ability to raise private capital is that it is a pioneering initiative in the African power markets. As AGC proves the viability of the operating model, AGC's capital can be adjusted to accommodate this substantial pool of capital. As with insurance markets, AGC is an inherently attractive entry point for investors by providing:

- ④ portfolio diversification
- ④ local and international government support
- ④ a clear, focused operating model
- ④ efficient transaction execution and power trading expertise
- ④ synergies with wider infrastructure investment strategies in power generation and transmission as well as economic activity benefiting from additional, more reliable power supply

However, raising capital from private investors should be balanced against the developmental objectives that AGC seeks to achieve. The return expectations for investors in AGC could be made more in line with commercial expectations with a leaner capital base for credit risk management, or through higher margins, which would shift the cost burden more on to the shoulders of the utilities and IPP investors. In both instances, over-emphasising commercial returns would undermine the net impact of introducing a creditworthy offtaker into the market.

Impact Investors

In recent years, certain pools of capital have emerged that seek to achieve certain non-financial objectives while safeguarding close to commercial returns. These can include foundations, endowments as well as High Net Worth (HNW) individuals and institutional investors.

This is a disparate group where different investors will have different investment guidelines and objectives. For example some foundations may have an interest to participate but can only do so through grants; other foundations and family offices may seek some nominal return, for example under the PRI guidelines; other private funds and family offices will seek market/superior rates of return. Each investor typically also has their own country/sector interest. These different interests need to be reconciled. It is recommended that AGC approaches a group of 10-12 investors in this category that might be interested in supporting AGC in order to gauge interest and likelihood of success in attracting funds. These could include:

- ④ African oriented Venture Capital investors seeking exposure to power market development and/or innovative renewable energy-specific strategies;
- ④ The Made in Africa Foundation, HomeStrings, and ONE, which are able to raise significant amounts from Africans at home and in the Diaspora;
- ④ Ultra-High Net Worth African investors such as Tony Elumelu and Aliko Dangote as well as South African and other entrepreneurs;
- ④ US and European foundations such as The Rockefeller Foundation, the Gates Foundation, Hewlett, Packard, Google and the Shell Foundation; and
- ④ Foundations and impact investing departments of major investment banks (e.g. JP Morgan Social Finance, UBS Optimus, Goldman Sachs Foundation, etc.);

On top of financial support, it may be possible for investors to provide in-kind support to AGC that helps to reduce its cost base and improve the probability and economics of successfully implementing the strategy. This support could take the form of staff, legal assistance, access to trading and information platforms and support on specific governance and operating logistics.

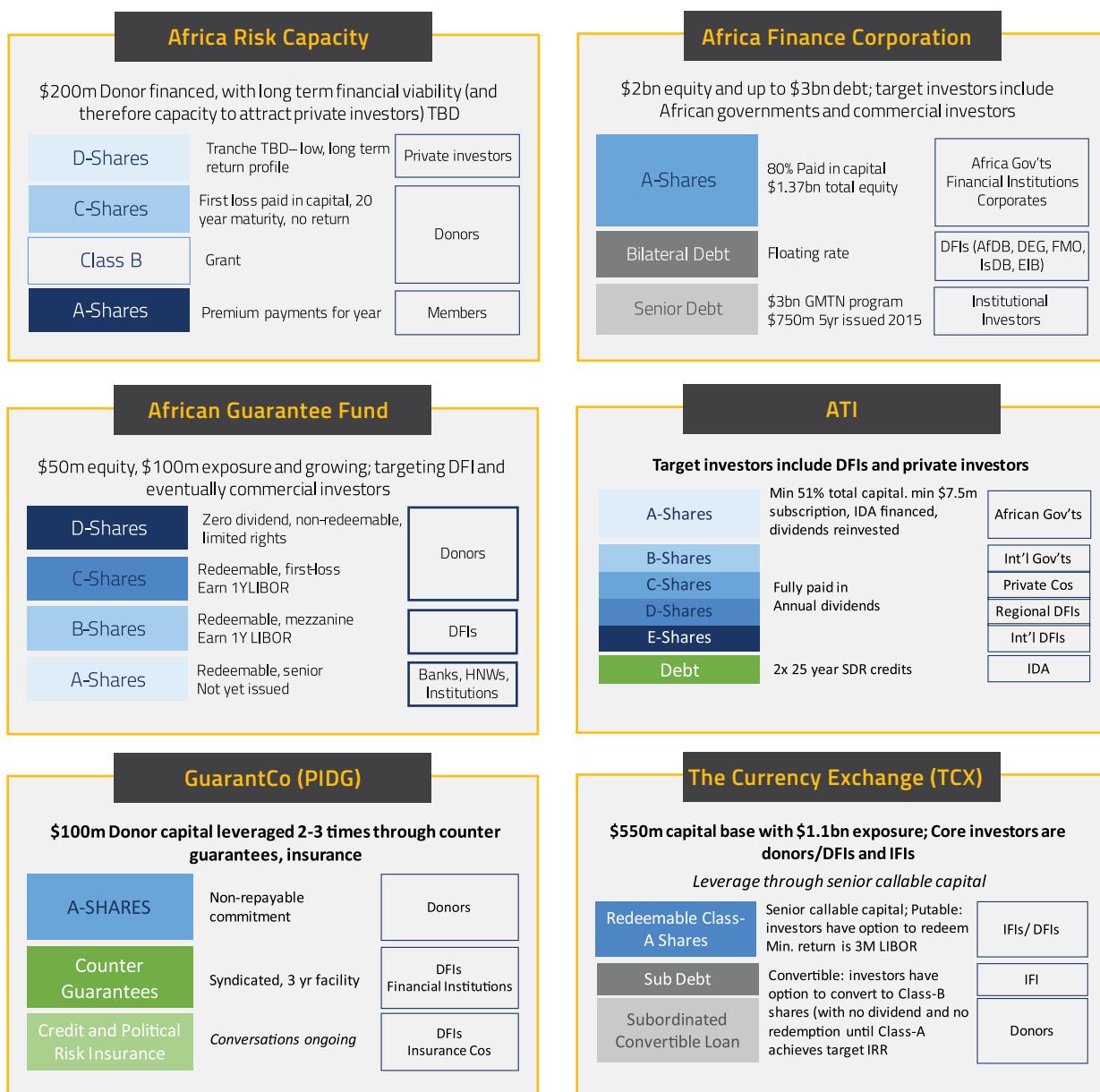
“ Ultimately, the goal of AGC is to pursue an operating model that can attract commercial and private capital. If AGC is able to develop a profitable trading and PPA intermediary business because i) margins are higher than expected or ii) market share and volumes of power transacted are higher than expected, then it may be able to replicate the success of PTC India in approaching private investors. This would create scope to grow the capital base and allow existing investors an opportunity to exit their positions. **”**

5.11.2. Tranching

The recommended equity structure is a trashed model, with distinct share classes for different investor classes. The reasons for this approach are that:

- ① the scale of funding potentially required is substantial and allowing as many different types of investor to participate can only help reach a target level;
- ② AGC is a new entity, has a relatively concessional pricing model and is aligned with climate and emerging market development priorities.

Trashed share structures are common in development finance, particularly for innovative initiatives. Vehicles such as EAIF and the DFIs themselves have a structure of permanent equity with no dividend, leveraged through commercial debt or mezzanine funding raised in the market. More recently, initiatives such as ATI, AGF, and ARC have been established with multiple share classes. Some examples of the resulting structures are set out below:



The main features of tranched capital structures include:

- ▶ **Accommodating donor investors** through a first loss/low return share class that is compliant with ODA concessionality thresholds (25% grant component under a 10% discount rate), as is the case with Class C subordinated convertible investors in TCX and the B and C Share tranches in ARC;
- ▶ **Returning capital to investors in different ways.** Tranching allow for shareholders to take on different return profiles – some entirely at risk as full equity investors, but with a share of any upside, others with a redeemable or convertible structure that creates more predictability around returns;
- ▶ **Promoting African ownership and political alignment with the strategy.** For many new strategies, one of the ways to align the ultimate beneficiaries is to create a share class that allows them to have an ownership stake in the success of the fund. This is the case for TCX, where MIVs and DFIs are encouraged to be investors. The logic is that currency exposures can be naturally hedged through TCX's fund and that covering these risks is the main purpose of investing, rather than achieving a return. Entities like ARC, ATI and AfreximBank, have distinct share classes for African governments. These share classes allow the governments to have a ring-fenced role in the ownership and governance of these entities. Given the highly politicized nature of power markets in Africa, the role of ministries, state-owned enterprises and regulators in governing how regional power pools have developed and the broader moral hazard/risk mitigation of AGC by giving African /host government skin in the game, tranching to allow control and investment by these governments is critical; and
- ▶ **Allowing investors to contribute capital using different instruments.** One of the challenges for new vehicles seeking capital from beneficiaries is how those beneficiaries will invest. In some cases, as in Africa50, governments invested directly in cash into the vehicle. In other cases, such as ARC and ATI, the tranching allowed investors to take ownership stakes through paid in premiums (ARC), potentially funded via IDA loans (ATI) and share premiums (ATI).

In basic corporate finance, the capital bearing the highest risk should receive the higher return. For structured development finance vehicles, the first-loss capital has a return of zero or close to zero, with any coupon reinvested in technical assistance. The junior tranche is provided by donors in order to attract other investors into the structure. These structures can also feature a number of tiers, recognizing that DFIs and private-sector investors have differing risk-return profiles.

Concessional equity capital can improve the risk return profile to other investors and may be crucial in convincing institutional investors to participate. The main issue is whether capital can be sourced on these terms at the required scale. Such tranching adds a layer of complexity as well, in that target returns for senior tranches, mechanisms for profit sharing, terms of conversion, and definition of subordination must all be part of fund/shareholder documentation.

TCX and ATI are different to the other funds in that much of their capital is callable from highly-rated shareholders (or IDA in the case of ATI). The advantage of callable capital is that there are no funding costs (e.g. LIBOR) and that investors can book their investment as a contingent liability – a positive for developed market and private investors since it allows them to invest beyond their capital base. The disadvantage is that it may not be regarded as Tier 1 capital by regulators; indeed, following the financial crisis and Sovereign downgrades in rich countries, ratings agencies are focusing less on callable capital in credit enhancement vehicles unless it is provided by highly rated investors (AAA sovereigns/supra-nationals). For this reason, we have not incorporated callable capital into the AGC model.

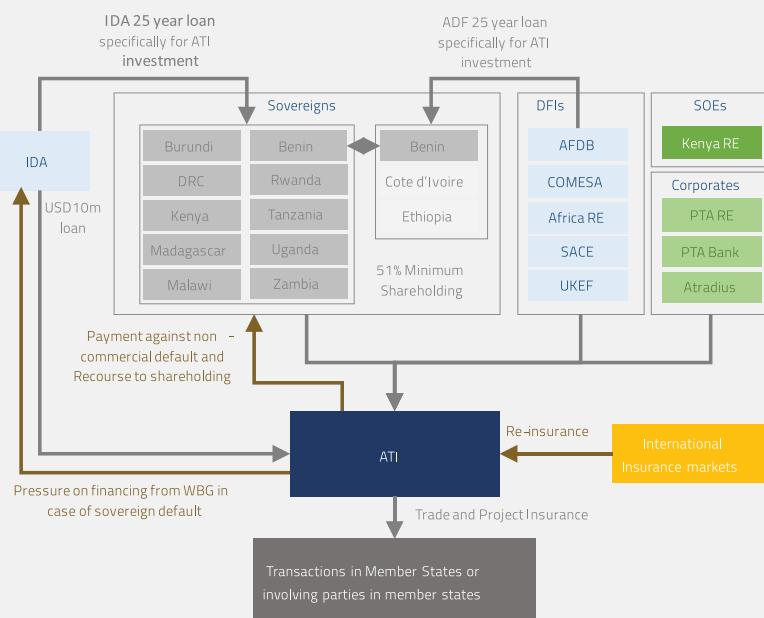
A review of its investment in TCX in 2013 by the German government stated:

“It is unlikely that a withdrawal of the subordinated loan Facility or a non-conversion into class B shares, would lead to an exodus of all existing Class A shareholders. However, for some shareholders the lower risk due to the first-loss embedded in the Facility is viewed as a significant compensation given the low return and the innovative character of the fund.”

Africa Trade And Insurance Agency

ATI was created in 2001 to fill a very specific need. At the time, foreign investors were avoiding the continent based on perceived notions of elevated levels of political risk. To make Africa more attractive as a foreign investment destination, a group of COMESA member countries supported by the World Bank launched the African Trade Insurance Agency (ATI) in 2001. ATI provides political risk/investment and, since 2006, ATI also covers commercial (payment default) risks. ATI's tranches capital structure is particularly relevant to AGC as it combines all the features described above for many of the same purposes that AGC is hoping to achieve. Specific features applicable to AGC are that:

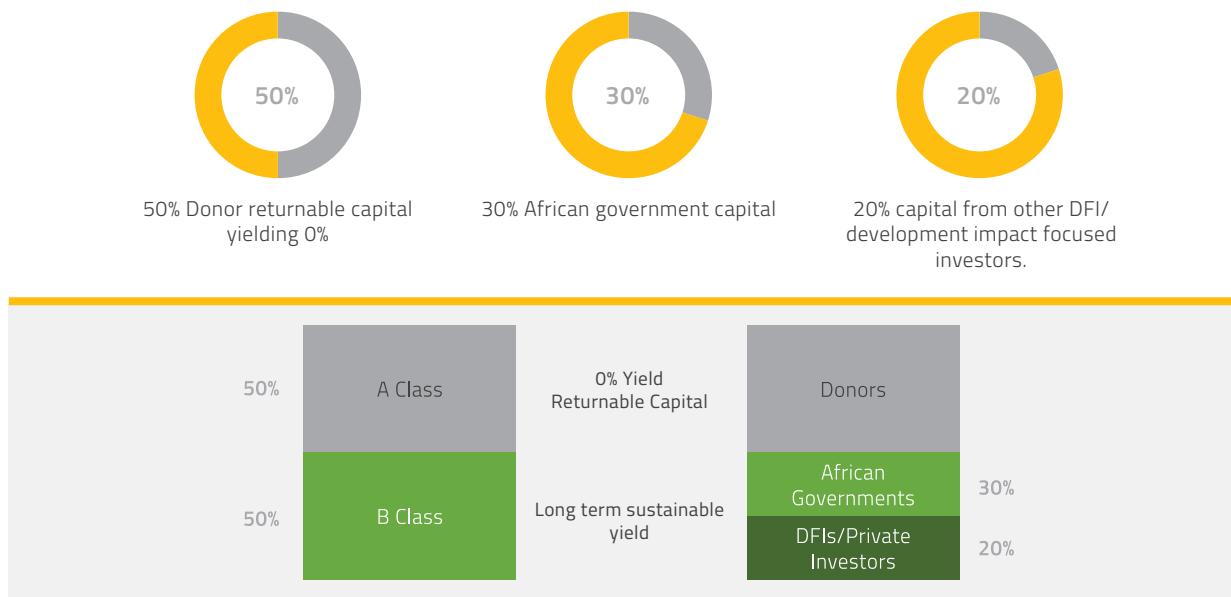
- ▶ ATI is majority owned by African governments, and has 10 active state members and a growing set of potential investors, with 3 additional members (Ethiopia, Cote d'Ivoire and Zimbabwe) expect to complete investment in 2015/6;
- ▶ ATI also has support from key regional DFIs (AFDB, COMESA, Africa RE) and bilateral DFIs (SACE, UKEF) with a strategic interest in ATI's underlying trade and investment credit mitigation;
- ▶ ATI allows investment by state-owned enterprises, namely Kenya Reinsurance Company;
- ▶ ATI also raised capital from private shareholders with strategic alignment to emerging market trade and investment credit mitigation;
- ▶ ATI's products are marketed to transactions, projects, companies and investors based in member countries; while there are products being developed to insure and re-insure non-member country risk, the main focus is to benefit only countries participating as shareholders
- ▶ ATI's sovereign shareholdings were supported by long term concessional loans to those sovereigns from the World Bank's Regional IDA window and the AfDB's ADF;
- ▶ ATI can deduct the funds due from a member's capital contribution and revoke membership if that member does not reimburse ATI for a non-commercial (i.e. political) risk event losses. Membership and forfeited shares may only be reinstated following full reimbursement of the loss to ATI.
- ▶ DFI involvement as investors and by supporting sovereign shareholders provide credit mitigation, in that sovereign default on payment against losses is less likely; if a sovereign is in default they risk access to other concessional capital and grant support
- ▶ ATI has managed its net exposure and leveraged its equity base by ceding risk to international re-insurance markets



5.12. Recommended Financial Structure

The recommendation is to apply a tranches capital structure to AGC. The size and terms of each tranche will ultimately be determined by investor feedback on appetite and capacity to deploy capital. The capital structure will likely evolve over time as the AGC strategy is proven and adapted to the realities of doing business on the ground.

The simple tranches structure proposed for AGC is:



This structure creates a 50/50 split between capital with no upside and capital that generates returns – the exact ratio can be adapted depending on what investors are looking for in terms of yield; if the market feedback is that investors are seeking higher returns, the proportion of returnable capital can be increased (or else the price and volume of the power traded will need to increase on the same capital base). If investors are willing to take more risk and lower returns, the capital structure can be weighted to allow them a greater share and reduce the donor returnable capital tranche.

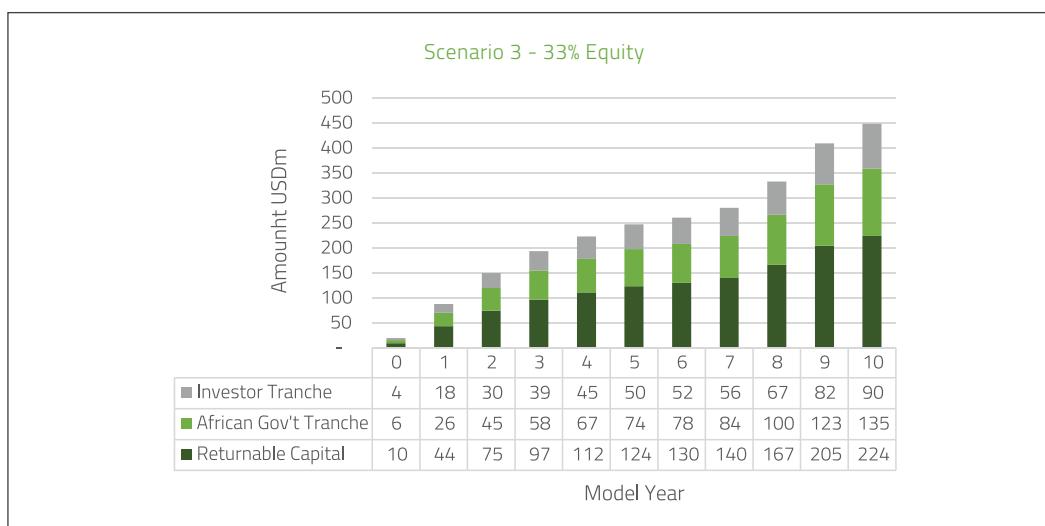
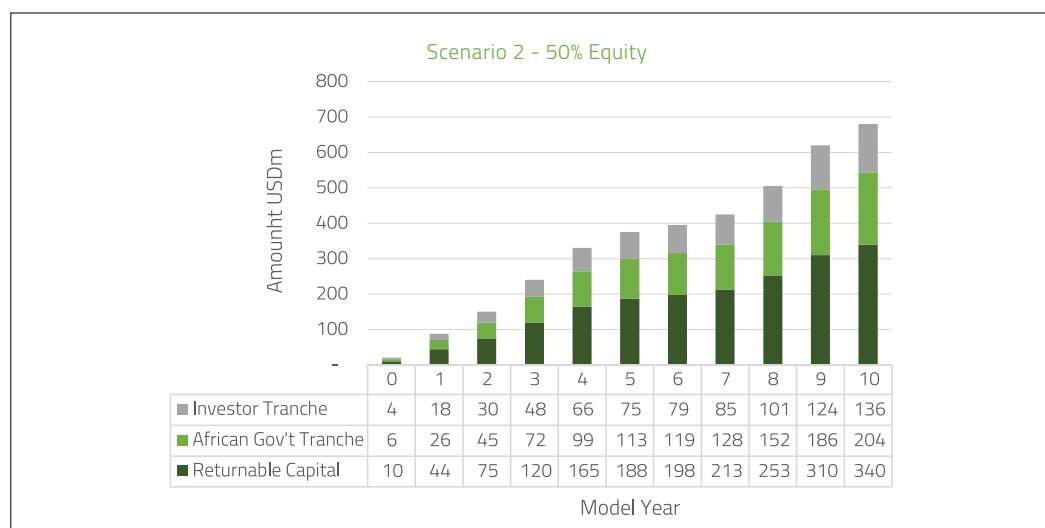
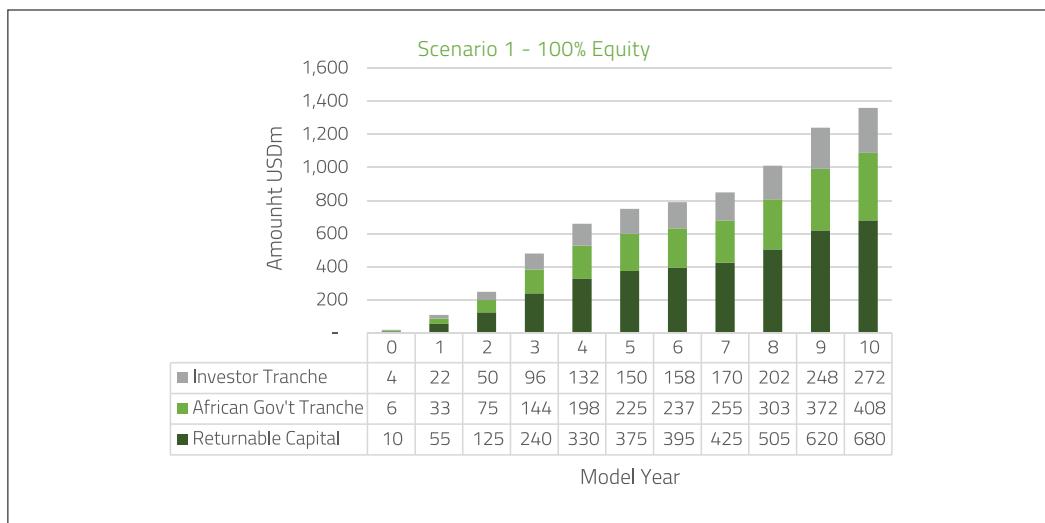
The main considerations behind this recommendation are that:

- ▶ AGC's strategy in terms of minimal margins on both PPAs and short term trading means that the returns are highly concessional. Donor returnable capital seeks capital preservation and possibly a modest return. In practice returnable capital transactions range from modest negative returns to positive returns. An example of a modest negative return is an entity like AgDevCo, which currently has a negative IRR but a long term objective of break-even/financial sustainability. Incorporating 0% yielding returnable capital into AGC can catalyse third party investment;
- ▶ Incorporating African sovereigns as shareholders is a priority – AGC will not succeed without African financial and strategic ownership of the concept. Creating a distinct share class/tranche for this capital will allow for additional structuring in terms of how African governments make their investment and what recourse AGC has to in case of a sovereign default; and
- ▶ Tranches can also be used to accommodate DFIs and other development-oriented investors by providing seniority in the capital structure and ring-fencing returns.

Under each of the three leverage scenarios (100% Equity, 50% Equity and 33% Equity), this creates different expectations about the quantum of capital required. Assuming a constant ratio between the different tranches:

- ② Funding AGC's exposure 100% through equity (as a benchmark rather than a recommendation) would ultimately require USD680m Class A returnable capital; USD408m investment by African governments and USD272m additional private/DFI capital by year 10;

- ④ Funding 50% of AGC's exposure with equity would ultimately require USD340m Class A returnable capital, USD204m investment by African governments and USD136m investment by other private/DFI investors by year 10 as well as access to USD680m guarantee/re-insurance on AGC's portfolio; and
- ④ Funding 33% of AGC's exposure with equity would ultimately require USD224m Class A returnable capital, USD135m investment by African governments and USD90m investment by other private/DFI investors by year 10 as well as access to USD911m guarantees/reinsurance support/re-insurance of AGC's portfolio.



5.13. Financial Performance

In terms of fundamental financial performance under each of the scenarios above, AGC has a limited, but long term financially sustainable return.

- Average long term Return on Assets (ROA) projections of around 0.72%
- Average long term annual Return on Equity (ROE) projections of 0.78%

Initially, AGC has negative ROA and ROE as it grows its capital base and provisions against liquidity and termination losses. In the long run, as the portfolio becomes diversified and provisioning requirements plateau, AGC begins to generate positive ROA and ROE.

The internal rates of return generated by AGC's free cash flow, (assuming exit in year 10) under each of the leverage scenarios are as follows:

Return Profile for Tranches of investors and Leverage Scenarios

IRRs for Equity Holders	Equity %	Scenario 1 All Equity	Scenario 2 50% equity	Scenario 3 33% Equity
No tranching – equity return	100%	1.47%	1.43%	1.19%
Returnable Capital Tranche	50%	0%	0%	0%
Investor Tranches (Pari Passu African Gov'ts/DFIS)	30%/20%	3.39%	3.33%	2.80%

The overall rate of return for AGC ranges from 1.19-1.47%. The tranching structure essentially doubles the IRR for the Class B shareholding. Allowing for a 50% Class A tranche that generates 0% return (but preserves its principal value) the remaining 50% of investors could generate returns of 2.80-3.39%.

Depending on the margins, guarantee cost and operating costs, the returns relative to leverage can behave counterintuitively - as leverage increases, one would expect equity returns to increase, but with low margins and a cost of leverage higher than the overall rate of return of the model, the returns will be lower for scenarios with less equity, since accessing guarantees generates additional costs. As a result, returns under this pricing model fall as more capital is acquired through leverage. This is a result of:

- ▶ AGC's pricing model has a low gross margin (approximately 3%) on its core business of buying and selling power, which after operating costs has a margin of 1-2% (increasing as AGC scales);
- ▶ AGC's investment model on excess capital generates 2% net returns;
- ▶ Increasing leverage reduces excess capital – so reducing the amount of capital that can back stop PPA contracts and generate 2% returns and creating a cost in terms of accessing guarantees;
- ▶ Under a fully equity funded scenario and 50% equity scenario, we therefore end up with higher returns than for a 33% equity scenario.

In order to provide the Class A shareholders with a long term exit strategy, AGC can structure the Class A shares such that they are convertible into yielding shares once AGC has become financially sustainable – at which point there may be opportunities for the Class A shareholders to exit to strategic and institutional commercial investors noted above. This exit scenario for donors and other impact investors will materialise once AGC has i) achieved sufficient portfolio diversification – i.e. a balanced portfolio of 10+ projects in multiple countries, which is anticipated for year 10 and beyond and ii) has established a market-based pricing and operating model that allows it to generate returns – i.e. has greater information on acceptable margins and the balance between short term trading and long term offtake contracts. These considerations are discussed in more detail in [Section 5.4.3 \(Short Term Trading\)](#) and the sensitivity analysis section below.

This level of return is low but in line with comparable development finance vehicles. For example:

- ⌚ TCX achieved return on equity of more than 6-month LIBOR (currently 0.9%) between 2008 and 2012, and paid investors a dividend of USD 13.7 million dividend in 2012, a yield of 2.5% on net assets;
- ⌚ AGF targets 1y LIBOR returns (currently 1.25%) for B and C share class investors – consisting of donor and DFI capital seeking a small return;
- ⌚ Microfinance investment vehicles, a common entry point for impact investors to participating in emerging market, developmental activities, typically generate 2-3% returns to investors net of fees.

However, as noted above in reviewing debt options, any investment in this strategy under the conditions described above is highly concessional given the risk profile for AGC as a new initiative in untested markets. The vehicle, if successful, offers a stable return and protection of capital; however, it is not a conventional commercial investment. Any model for AGC that gives confidence to IPPs against payment in case of default independent of utility or sovereign payment under the PSA requires substantial capital. Simultaneously, to ensure value for the utilities, margins are minimal. The resulting structure for AGC is a permanent capital vehicle rather than corporate (e.g. ATI) or fund (e.g. AREF): shareholders' cash (and upside) is not returned at a pre-defined maturity date and it may not be straightforward to sell shares and exit.

It should be noted that under this pricing model, net income does not become positive until year 4 for 100% equity, and year 7 for 50% or 33% equity. This loss reflects the conservative provisioning ratio (10%) against exposure. On an operating basis alone, AGC is generating positive income in years 3-4. With more flexibility on provision or with a more aggressive pricing model, the return profile and timing can be adjusted to fit investor requirements.

5.13.1. Sensitivity Analysis

The AGC model is broadly resilient to a range of variations in the operating model. AGC's profitability and investment profile is a function of:

⌚	Volume of power traded under PPAs/PSAs and in competitive markets;
⌚	Pricing and margin on those transactions;
⌚	Operating expenditure required to implement the transactions; and
⌚	Cost of leverage through guarantees/re-insurance required (if there is leverage).

This section reviews how these different inputs affect AGC's risk profile – and how they can act as key levers to adjust the operating model in order to improve financial sustainability.

- ⌚ AGC's role as a trader combines a forecast market share (increasing to 20% in the long run) with the SAPP's projections for annual growth in the competitive market (10% per annum). These forecasts are quite speculative – historic market activity has been very volatile. Therefore it is important to understand how deviation from the forecast of traded power volumes impact returns. The low 3% trading margin means that the effects of increases in traded power are muted – as the table below shows, halving or doubling the amount of power traded keeps returns in line with the base case model.

All equity IRR	Scenario 1 - All Equity	Scenario 2 - 50% Equity	Scenario 3 - 33% Equity
AGC trades half as much as forecast	1.41%	1.32%	1.00%
Base Case	1.47%	1.43%	1.19%
AGC trades double the forecast	1.58%	1.66%	1.56%

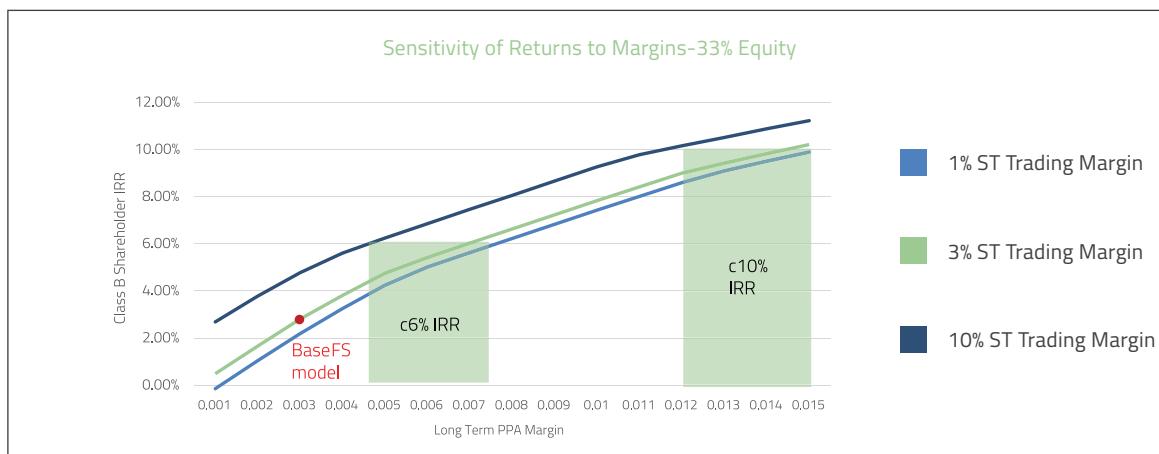
Class B Shareholder IRR	Scenario 1 - All Equity	Scenario 2 - 50% Equity	Scenario 3 - 33% Equity
AGC trades half as much as forecast	3.25%	3.05%	2.34%
Base Case	3.39%	3.33%	2.80%
AGC trades double the forecast	3.67%	3.92%	3.74%

- Revenues are much more sensitive to the average ratio of power sold that has been purchased under the PPA. AGC cannot sell more than 100% of power purchased; therefore this sensitivity is focused on reducing downside in a default scenario rather than increasing any upside. The minimum level of power sold under each scenario is:

PPA Sales Ratio	Scenario 1 -All Equity	Scenario 2 - 50% Equity	Scenario 3 - 33% Equity
Breakeven (IRR=0)	87.9%	95.1 %	97.25%

The higher the leverage of AGC the more exposed it is to an ability to sell power in case of default. At 67% leverage, AGC must be able to sell 97.25% of all power purchased. Leaving any volume of power purchased under the PPA open to competitive trading creates a risk for AGC – if it fails to make those sales, AGC will not be financially sustainable. PTC India addressed this issue by signing take-or-pay contracts with Offtakers and having a short term, fully collateralized billing cycle – if an Offtaker defaulted, PTC could draw on a letter of credit against power purchased up to that point and then stop supplying all power to that Offtaker (i.e. power purchased under the defaulted PSA and any other PSAs with that Offtaker) and find an alternative purchaser. As discussed in *Section 7.10 (Credit Support Arrangements and AGC's Credit Mitigation Strategies)* AGC intends to have similar rights in order to mitigate credit risk on its Offtakers in the absence of a sovereign guarantee.

- The current margins are USDc 0.3/kWh on PPA contracts and 3% on short term trading – selected against benchmarks from PTC India's experience as described above. If AGC is able to achieve higher margins – and still add value to utilities – the returns to investors can increase substantially. The impact on the IRRs under a 33% equity scenario are featured in the graph below. The x axis is used for the PPA margin in USD/ kWh. The top dark blue line represents the returns for different PPA margins if the Short Term Trading margin is 10%. The bottom, light blue line represents the returns for different PPA margins if the short term trading margin is 1%. The green line represents returns for different PPA margins using the current 3% short term trading margin assumption.
- The process for setting margins should be transparent and operate in collaboration with the key SAPP regulators and utilities – but one reasonable input may be selecting a target that is able to attract sufficient capital into AGC (and future trader/intermediary market entrants). AGC is more likely to attract sufficient capital (from a wider universe of investors) if the Class B shareholder IRR is e.g. 6% versus 2.8%. Using illustrative numbers and assuming a 33% equity base, investors can increase IRRs to 6% by increasing



the PPA margin to 0.7 USD cents or higher. That would be comparable to other impact investment and development finance vehicles. To achieve returns of 10% or more, AGC would need to charge PPA margins of USDc 1.2-1.5/kWh.

- The margin AGC is able to charge will also be a factor of how much of a reduction in PPA tariffs AGC can achieve through its role as a creditworthy intermediary Offtaker, both directly through reducing the credit risk profile of individual projects and indirectly through expanding the field of potential investors and the resultant competition driving margins and return expectations down. The bigger the reduction, the more margin AGC can charge without increasing the PSA tariffs. For a description of the scale of tariff impact, see *Section 6 (Impact on Power Markets)* below.

- Operating costs are low relative to the size of capital required to back stop PPA exposures. Long term costs of USD4.5m for operations and treasury management on a base of USD450m equity for the 33% equity scenario is roughly 1% and well below typical development finance investment vehicles. However, that assumes a small team and lean operating model; if AGC's operating costs increase to support a larger team with more of a corporate structure, or transactions required additional legal, financial and technical support, the impact on returns is amplified by leverage. If basic operating expenses double, investor IRRs with 33% leverage fall from 2.80% to -0.06%

All equity IRR	Scenario 1 - All Equity	Scenario 2 - 50% Equity	Scenario 3 - 33% Equity
100% of Opex Costs (Base)	1.47%	1.43%	1.19%
150% of Opex Costs	1.32%	1.06%	1.30%
200% of Opex Costs	1.16 %	0.65%	-0.06%

Class B Shareholder IRR	Scenario 1 - All Equity	Scenario 2 - 50% Equity	Scenario 3 - 33% Equity
100% Opex Costs (Base)	3.39%	3.33%	2.80%
150% Opex Costs	2.03%	2.43%	1.30%
200% Opex Costs	2.04%	1.49%	-0.15%

6

Impact on Power Markets

The principal goal of AGC is to stimulate private sector development of renewable energy in sub-Saharan Africa. In the process, the AGC model generates a number of critical benefits for the portfolio projects and countries in which those projects are located. This section reviews the various impacts including:

Benefits to projects and investors

- ⌚ Reducing transaction costs;
- ⌚ Improving the bankability of underlying IPPs;
- ⌚ Leveraging private capital to get projects executed;
- ⌚ Becoming an entry point for institutional capital as an aggregator of deal flow and credit risk - in terms of investment in projects through structured finance and provision of risk mitigation products at the portfolio level;
- ⌚ Cushioning investors from regulatory change resulting from the unbundling of national power markets;
- ⌚ Potentially acting as backstop offtaker on projects beyond its own portfolio; and
- ⌚ Increasing the scope for refinancing and therefore unlocking more capital from upfront lenders – who can be more confident of being able to pass on their positions after COD – and from local and international institutional investors who will be more likely to invest once the projects are operational.

Benefits to utilities

- ⌚ Increasing the installed capacity and generated power in the target markets;
- ⌚ Helping utilities reduce tariffs and thereby reduce balance sheet pressure;
- ⌚ Supporting the transition to cost-reflective tariffs for consumers through lower threshold commercially viable PPA tariffs;
- ⌚ Reducing utility and commercial and industrial offtaker dependence on expensive, fossil-fuel based emergency power; and
- ⌚ Maximising the utilization of existing power assets for utilities.

Benefits to sovereigns

- ⌚ Reducing the likelihood of PPA-related contingent liabilities crystallising (and in some circumstances reducing the quantum of such liabilities) and thereby reducing the balance sheet pressure and the detrimental effect on sovereign debt sustainability/indebtedness;
- ⌚ Avoiding emissions from equivalent long term fossil fuel power plants;
- ⌚ Creating employment during the construction and operation phase of each portfolio project;
- ⌚ Reducing the economic cost of power outages in terms of direct impact on industry/commerce and indirect barriers to investment;
- ⌚ Helping to catalyse more robust and active regional power markets; and
- ⌚ facilitating the move towards local currency PPAs.

6.1. Benefits for projects and investors

Taken together the potential impact of AGC in power markets is substantial. Each dollar invested under a 33% equity scenario generates \$5-\$6 additional financial benefit that is directly quantifiable. The operating model helps to unlock enough capacity to connect almost one million households to the grid and avoids 7m tonnes of

carbon equivalent, while generating over 20,000 new skilled jobs. The table overleaf provides a more detailed breakdown of these impacts with the total value split out over each different investor class.

Impact Per USD Invested in AGC by yr 10	Total USD Impact		Investment		Contingent Liabilities		Tariff Savings		Trade		Power		Additional Impacts			
			Total	Total	Low	High	Mid	High	Total	Inst. Capacity	Power Output					
			1,310	1,186	297	890	133	310	258	605	9,535,260	GWh				
100% Equity	Investment		USDm	USDm	USDm	USDm	USDm	USDm	USDm	MW	Power Traded					
Total	1,360	USDm	1.5	2.0	1.0	0.9	0.2	0.7	0.1	0.2	0.4	2,943,374	MWh			
Donor	680	USDm	2.9	4.1	1.9	1.7	0.4	1.3	0.2	0.5	0.4	0.7				
African Gov't	408	USDm	4.9	6.8	3.2	2.9	0.7	2.2	0.3	0.8	0.6	1.2	Electricity Access			
DFI/Private	272	USDm	7.3	10.2	4.8	4.4	1.1	3.3	0.5	1.1	0.9	1.8	970,000	Hholds		
50% Equity																
Total	680	USDm	2.9	4.1	1.9	1.7	0.4	1.3	0.2	0.5	0.4	0.7	Carbon Emissions			
Donor	340	USDm	5.9	8.1	3.9	3.5	0.9	2.6	0.4	0.9	0.8	1.4	7,800,087	tCOe		
African Gov't	204	USDm	9.8	13.6	6.4	5.8	1.5	4.4	0.7	1.5	1.3	2.4				
DFI/Private	136	USDm	14.7	20.3	9.6	8.7	2.2	6.5	1.0	2.3	1.9	3.6	ST Employment			
33% Equity													22,655	Jobs		
Total	449	USDm	4.4	6.2	2.9	2.6	0.7	2.0	0.3	0.7	0.6	1.1	LT Employment			
Donor	224	USDm	8.9	12.3	5.8	5.3	1.3	4.0	0.6	1.4	1.1	2.2				
African Gov't	135	USDm	14.8	20.6	9.7	8.8	2.2	6.6	1.0	2.3	1.9	3.6	1,014	Jobs		
DFI/Private	90	USDm	22.2	30.8	14.6	13.2	3.3	9.9	1.5	3.5	2.9	5.4				

6.1.1. Lowering transaction costs

Renewable energy projects in sub-Saharan Africa typically require substantial upfront development and transaction costs. These include (i) the direct costs of the specialist advice required to prepare feasibility studies and project documentation in countries with limited institutional support and (ii) the indirect costs associated with the extensive time and effort required to negotiate and execute each transaction. For modelling purposes, these upfront costs have been estimated to be around 10% of the total project costs depending on the project technology. While there are no universal benchmarks for the potential reduction in project finance transaction costs, the Azura OCGT IPP in Nigeria recently published a review of the total transaction costs incurred. Some highlights from that analysis include:

- The total hours of input required were estimated to be 442,000 – equivalent to 250 years for a single individual
- Reaching financial close took 6 years from start to finish
- Over 60% of development costs were incurred after the original estimated close date – which allowed 3 years – and the total cost increased five-fold from initial estimates over the development period
- The PPA required four years of negotiation and 17 stakeholders (direct and advisors) participated
- Once the PPA and Certificate of Occupancy were in place, the remaining agreements – which were heavily skewed to credit enhancement and financing – required 3 further years;
- Negotiating the Letter of Support and subsequent Put Call Option Agreement to ensure credit enhancement involved 21 parties and required 2.5 years
- Structuring the PRG and MIGA PRI cover with respect to NBET's offtaker creditworthiness entailed 12 separate agreements and negotiations took 4 years;
- In total the documentation for the project was 6,931 pages long – and entailed over 1000 iterations.

AGC's standardized contracting approach, legal and technical expertise and status as a public-private partnership can simplify and accelerate the process for both Generators and Offtakers. This should be reflected in developers being more willing to take development risk for the same forecast equity return, more efficient allocation of capital and ultimately, projects being banked in a shorter period of time. Assuming a conservative 10% reduction in transaction costs generates an average 0.2% increase in equity IRRs across the hypothetical portfolio.

6.1.2. Increasing Bankability

Through its role as a creditworthy intermediary offtaker, AGC aims to help make more projects bankable – i.e. reduce the perceived credit risk and improve the financial viability of the project. This impact most directly translates into lower interest rates and longer tenors from lenders which in turn help to improve equity rates of return and/or reduce electricity tariffs. Market feedback from lenders on the extent of AGC's impact on debt terms suggests a potential reduction in the interest rate of up to 3% and a potential increase in tenors from 8-10 years to 12-15 years.²³

The proposed 3% margin reduction is equivalent to (if not less than) the cost borne by investors in obtaining standalone credit enhancement, insurance and guarantees to mitigate offtaker risk and other risk elements. Concessional guarantees against sovereign risk are typically priced at around 1% and contractual risk insurance and other cover relating to the PPA is typically priced around 1-3%; for more detailed examples, please see [Annex 6 \(IPP Credit Enhancement Strategies\)](#). This also translates to the potential impact of a creditworthy offtaker on senior debt pricing and tenors – since the cost of risk mitigation is incorporated into the interest rate by most commercial lenders.

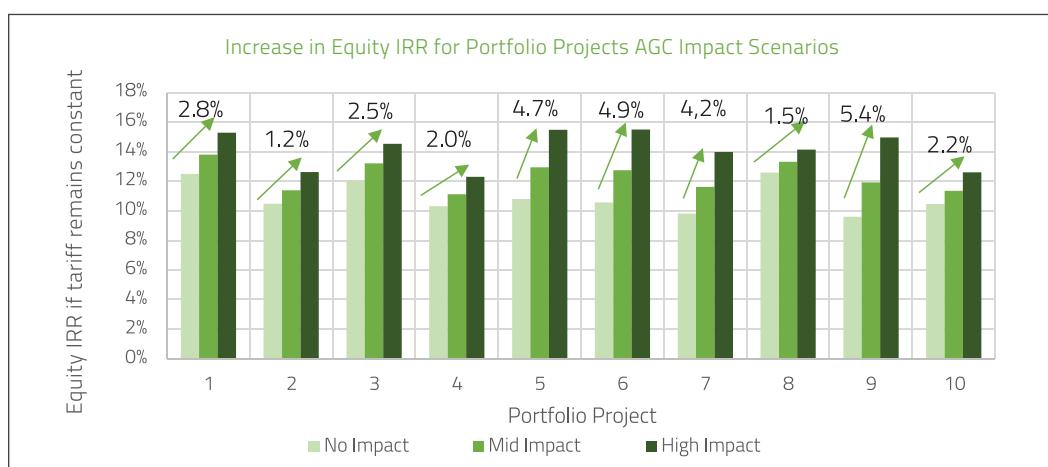
The table below describes the impact on the equity IRR of a 40MW Zambian hydro project – the first project in the hypothetical portfolio above – within those thresholds.

Return Profile for Tranches of investors and Leverage Scenarios

AGC impact on Cost of Debt								
Equity IRR	0.00%	-0.50%	-1.00%	-1.50%	-2.00%	-2.50%	-3.00%	
AGC Impact on Tenor of Debt	8	12.50%	12.66%	12.83%	12.99%	13.16%	13.33%	13.51%
	9	12.65%	12.83%	13.01%	13.20%	13.39%	13.58%	13.78%
	10	12.79%	12.99%	13.20%	13.40%	13.61%	13.83%	14.04%
	11	12.94%	13.16%	13.38%	13.61%	13.84%	14.07%	14.31%
	12	13.08%	13.32%	13.56%	13.81%	14.06%	14.31%	14.57%
	13	13.22%	13.48%	13.74%	14.01%	14.27%	14.55%	14.82%
	14	13.36%	13.64%	13.92%	14.20%	14.49%	14.77%	15.07%
	15	13.50%	13.79%	14.09%	14.39%	14.69%	15.00%	15.31%

Under the pre-AGC base case (8 year debt tenor, sovereign benchmark interest rate), the equity IRR is estimated to be 12.50%. If AGC is able to help developers access lower cost (-300bps) and longer tenor (15year) debt, the equity IRR can rise to 15.31% - i.e. the project becomes financially viable.

Across the portfolio of projects, this has a dramatic effect – helping to improve internal rates of return for equity holders by as much as 4.7% - and taking previously marginal/unbankable projects above a threshold of potential interest (NB this rate of return is at the assumed tariffs referenced above). The mid-level potential impact is 1.2% increase and the high level potential impact is 3.3% across the whole portfolio.



²³ Noting that lenders are also under Basel III constraints to match long term funding to long term lending – and that therefore longer tenors are currently more challenging independent of offtaker creditworthiness

While this impact is substantial, it must be compared to the negative impact of the proposed AGC margin on the tariff received by the IPP. While we describe this cost as being borne by the IPP the actual effect will be more nuanced – in that PPA tariff negotiations will still seek to align utilities' ability to pay with IPPs' financial viability. However, assuming a USDc 0.3/kWh margin falls wholly on the IPP, the negative impact is 0.65 – i.e. if the IPP had a direct contract for the full PSA value the Equity IRR would be 0.65% higher.

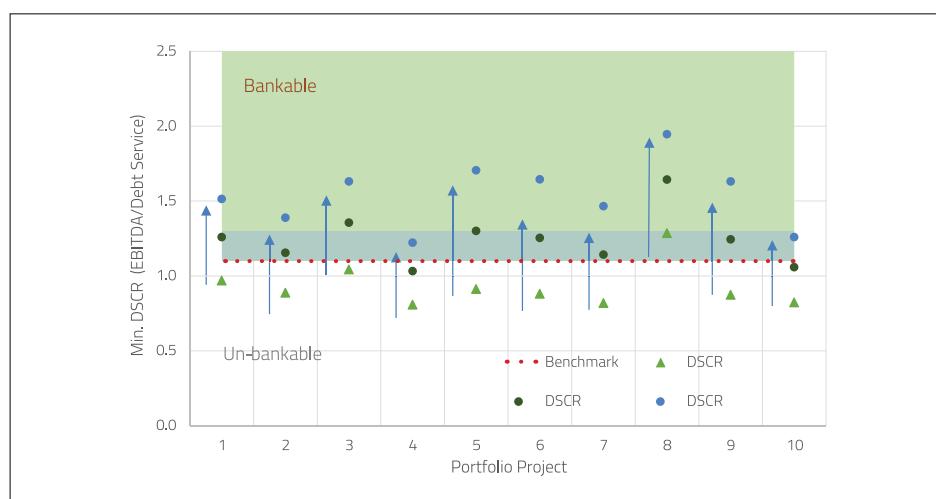
A further benefit of increased bankability is an increase in the leverage achievable. A higher proportion of debt in a project improves the equity IRR and frees up equity to invest in other projects, thereby expanding the number of projects that can be backed by the same overall quantum of available equity.

In parallel with the equity returns, the viability for lenders also improves. With longer tenors and lower cost of debt, the debt service coverage ratio improves, since the interest and principal repayments should be lower in each period. For the Zambian 40MW hydro project, this effect on DSCR can shift the minimum DSCR of a project from 0.97 to 1.51, and the average DSCR from 1.27 to 2.18 as set out in the table below.

AGC Impact on Debt Service Coverage Ratio for sample project

DSCR (Min)	AGC impact on Cost of Debt							
	0.00%	-0.50%	-1.00%	-1.50%	-2.00%	-2.50%	-3.00%	
AGC Impact on Tenor of Debt	8	0.97	0.99	1.01	1.03	1.05	1.08	1.10
	9	1.03	1.05	1.07	1.10	1.12	1.15	1.18
	10	1.08	1.10	1.13	1.16	1.19	1.22	1.25
	11	1.12	1.15	1.18	1.21	1.24	1.28	1.31
	12	1.17	1.20	1.23	1.26	1.29	1.33	1.37
	13	1.20	1.24	1.27	1.30	1.34	1.38	1.42
	14	1.24	1.27	1.31	1.34	1.38	1.42	1.47
	15	1.27	1.31	1.34	1.38	1.42	1.47	1.51

Across the portfolio as a whole, the average potential impact is an increase in DSCR of 0.54 and all projects cross a threshold of a minimum DSCR of 1.1



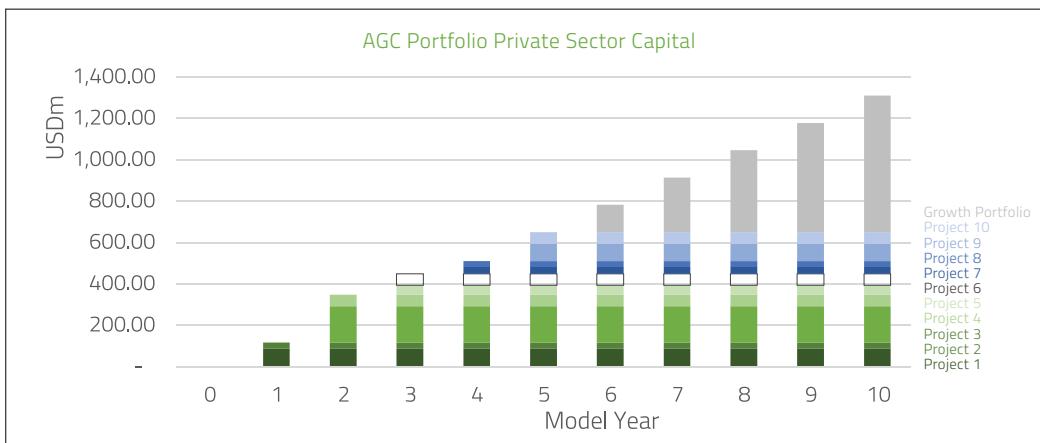
Reducing the risk profile of loans will also impact upon the risk weighting and capital adequacy rules applicable to such loans, enabling lenders to advance more loans against the same capital base. This increased efficiency will make more debt available and should also help reduce the margins applied.

6.1.3. Attracting Private Capital

On this basis, we expect the introduction of AGC to unlock new and expand existing capital providers' scope to deploy capital into the African energy sector and reduce the heavy dependence on DFI capital. In parallel, this will develop the capacity and experience of investors in terms of the wider regional and sector expertise and have a

knock-on effect in unlocking projects that are not directly supported by AGC. This indirect effect can be seen most clearly in South Africa – where lenders are increasingly comfortable lending to RE projects regionally having built up expertise under the REIPPP program.

“In terms of private sector capital, the model forecasts that AGC will be able to unlock an additional USD1.31bn of investment in IPPs, which is a conservative estimate as it is based on no private capital incentivised through AGC’s trading activities.**”**



6.1.4. Entry point for Investment

Beyond the direct benefit to IPP investors, AGC, by building a portfolio of pipeline and active projects, can act as a conduit for increased financing into the renewable energy sector. To institutional lenders and investors, most African renewable energy projects are below the threshold for minimum transaction size. To the extent that AGC builds a portfolio, it may be able to structure a standalone facility for financing this portfolio with international and local institutional investors. As noted earlier, MASEN has played this role on a project-by-project basis in Morocco for concessional lenders, by having a blended pool of debt available to projects selected through its procurement process.

6.1.5. Entry point for Risk Mitigation Instruments

In addition, AGC will act as a conduit for other financial instruments (beyond equity and debt). Current uptake amongst international financial institutions offering risk mitigation for infrastructure is minimal. IRENA found that the ratio allocated to renewable energy ranged from 0-13% and averaged 4% across 16 institutions. With the leverage scenarios described above actively seeking third party guarantees and insurance on 50-70% of the portfolio exposure, ultimately AGC will introduce USD 1bn of additional deal flow to public and private risk mitigation providers, as noted above in *Section 5 (Financial Viability)*.

For private markets in particular there is greater demand for taking on risk through structured transactions comprising a portfolio of projects. For example, Munich Re provided multi-well risk mitigation insurance across a portfolio of geothermal test wells in Kenya, and Barclays has partnered with KfW to counter-guarantee GuarantCo's portfolio up to USD400m. AGC's potential role as an aggregator of renewable energy project risk can help lower due diligence costs, better conform to investor requirements, broaden the investor pool and diversify individual asset risks. AGC also creates value for the IPPs – the main barriers cited by developers and investors to accessing credit enhancement products were lack of product awareness, concerns about processing times and costs, and lack of capacity to manage the application and reporting requirements²⁴. AGC can absorb these costs for IPPs – increasing the overall efficiency of the transactions and taking the burden from them.

AGC may also be able to catalyse the market for foreign exchange hedging products, although the current market capacity is limited. Even if hedging were available, the requirement to post collateral could potentially absorb a large portion of AGC's capital unless it is able to insure this risk or obtain a guarantee in respect of such contingent liability.

²⁴IRENA (2016), 'Unlocking Renewable Energy Investment: The Role of Risk Mitigation and Structured Finance' IRENA, Abu Dhabi

6.1.6. Cushioning investors from regulatory change resulting from the unbundling of national power markets

As AGC will be the contractual counterparty to the IPP, regulatory change and market unbundling affecting the legal status of the offtaker will have no direct impact on the PPA. AGC will be better placed to manage such regulatory changes on a portfolio basis and against the backdrop of its membership including the African governments.

6.1.7. AGC as Backstop Offtaker

Beyond acting as creditworthy offtaker for the IPPs within its direct portfolio and insulating them from the risks associated with offtaker default, AGC could also generate an additional revenue stream, by acting as a backstop offtaker in respect of third party projects, thereby also reducing their reliance on the incumbent offtaker and the associated requirements for credit support. Its ability to do so would be similarly subject to technical analysis regarding potential replacement offtakers in each case and its ability to do so will increase as its portfolio of offtakers increases.

6.1.8. Enabling environment for refinancing

Another key issue that Africa GreenCo will help to address is the market for refinancing. Fundamentally, refinancing of African power projects is in its infancy; institutional investors locally and internationally view most transactions as too small and high risk to invest in. With AGC improving the offtaker credit risk and aggregating a portfolio of projects, the refinancing market should be more favourable. Unlocking refinancing also addresses lenders' Basel III constraints. Basel III requires lenders to match the tenors of their lending with their funding sources. For project finance, this creates a capacity constraint: there is less long term funding available to lenders to be able to deploy at 15 year+ tenors. One result of Basel III is that transactions are increasingly being structured to incentivize refinancing after COD and up to around the 7-8 year mark. AGC's potential impact in the market is to give lenders more confidence that they will be able to refinance due to the improved credit profile of the project. To the extent that AGC can also add an aggregation dimension – increasing transaction size, reducing diligence and execution costs and reducing exposure to individual asset or country risk - this is a win-win.

6.1.9 Foreign Currency Exchange Risk and Local Currency PPAs

As further discussed in *Section 5.9 (Foreign Currency Exchange Risk)*, the core recommendation on currency risk from stakeholders engaged as part of the preparation of the Feasibility Study was that tackling both credit and currency risk would be too broad a remit for AGC to successfully implement initially.

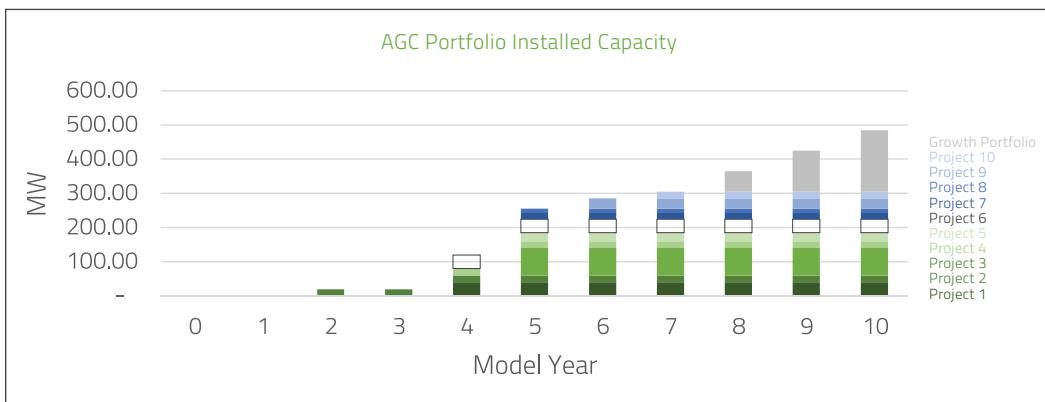
Moving towards (part) local currency PPAs should be an objective for most African countries. This is likely to be a gradual process, given high local interest rate environments in many countries and local banks' limited capacity to provide long dated fixed rate financing.

AGC is well placed to play an important role in this process. However, any foreign exchange intermediation by AGC needs to be looked at individually and may require additional financing and liquidity support to protect AGC's investment grade rating. Once AGC has demonstrated that it can address the wider credit risk issue, it should explore the option of layering on more sophisticated strategies to manage currency risk. In the interim, AGC can explore project-by-project opportunities to mitigate currency risk without AGC taking exposure – i.e. through partnerships with parallel initiatives that are explicitly designed to tackle local currency issues such as GuarantCo and TCX.

6.2. Benefits to Utilities

6.2.1. Increased power supply

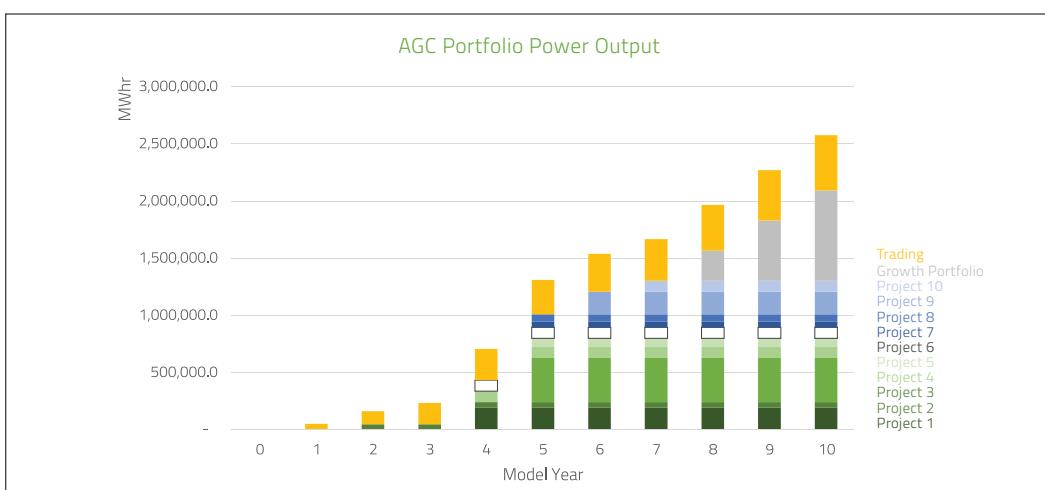
Using AGC's hypothetical portfolio of projects, we can forecast how much power AGC will help bring to the market. In terms of installed capacity, based on the 10 projects and longer term growth in such portfolio, the model forecasts that AGC can help catalyse 485MW additional installed capacity in the region to be operational by the end of year 10 with a further 60MW under construction and PPAs signed for another 60MW. This would obviously increase as AGC's capital base and/or leverage increases and it is able to back more projects.



“ While this level of installed capacity may seem small relative to the large power deficit, it should be noted that the current model has been designed for proof of concept with small-medium sized IPPs, but that AGC is highly scalable: once the model is proven it can be applied to larger projects. ”

The internal limiting factors for AGC's growth are capital and diversification - acknowledging that as the market develops, the potential for new interconnections and cross-border trading is expected to grow in parallel in line with SADC's Regional Infrastructure Development Master Plan. At the outset, AGC will struggle to raise the quantum of capital required to act as a creditworthy offtaker for multiple large scale projects, and applying AGC's initial capital to support a small number of large projects will reduce AGC's ability to create a diversified portfolio in order to mitigate risk and maintain its creditworthiness. Once established and operational with a portfolio of assets, AGC expects to be able to access additional capital and add larger scale projects to its portfolio as well as recycle capital from net income and from amortizing exposures elsewhere in the portfolio. The impact on the cost of capital will be numerically the same. Key qualitative differences for larger projects are that AGC will help to reduce transaction costs and time to financial close, for example by acting as a single-point offtaker, taking the burden of negotiating with multiple offtakers away from the Generator. By enhancing the creditworthiness of larger projects, AGC should be able to catalyse local or international institutional capital, which can take on the larger ticket sizes associated with these projects alongside the current donor and DFI flows.

In terms of power output purchased by AGC, the model forecasts over 2 TWh of power purchased annually under long term contracts and almost 3 TWh traded over the first ten years of operation.



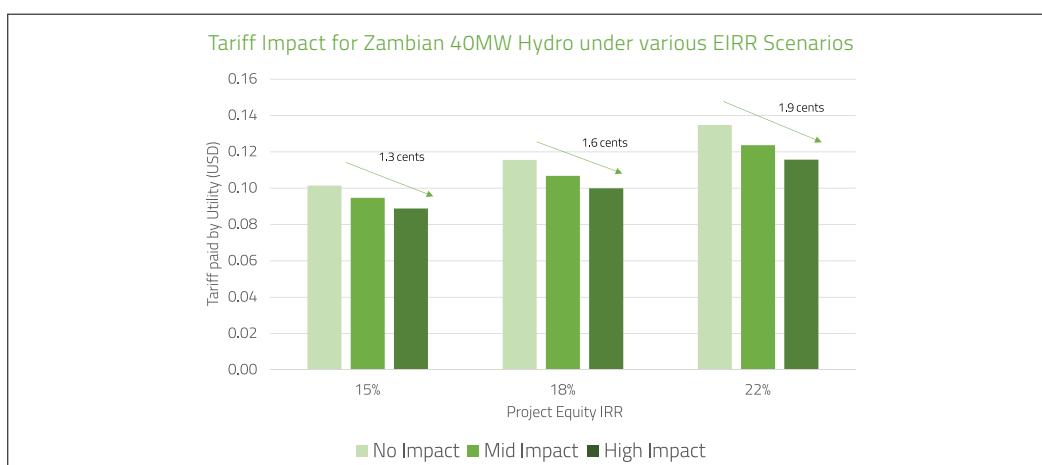
6.2.2. Supporting the Transition to Cost-Reflective Tariffs

It is widely recognised that a transition to cost-reflective tariffs is essential in order to improve the creditworthiness of Offtakers and ensure the long-term sustainability of the African power markets. However increasing retail tariffs is a highly politically sensitive issue and typically involves a well-designed tariff transition plan. Various initiatives are underway in order to assist with this transition, including through AfDB's New Deal on Energy for Africa and under the auspices of Power Africa. While AGC has no direct role in this process, it can indirectly assist

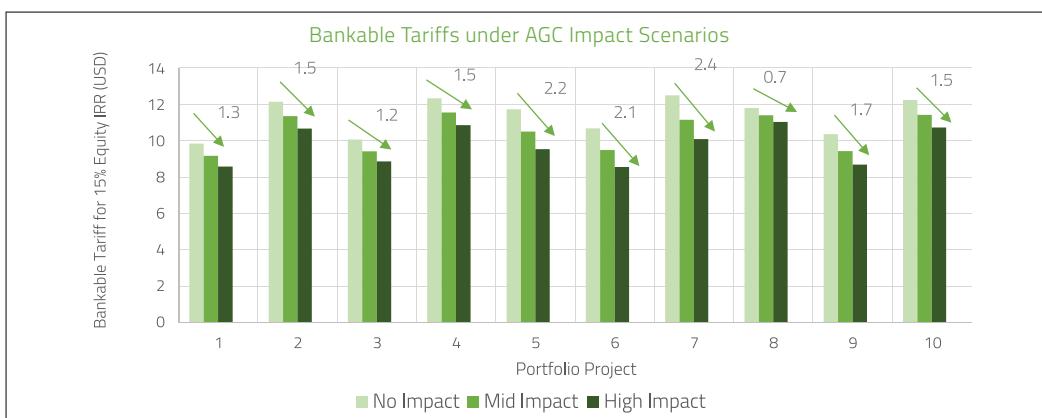
in such transition in a number of ways, including:

- ⑤ by reducing wholesale tariffs as a result of lower project financing costs due AGC's role as a creditworthy counterparty to the Generator's PPA and power trader;
- ⑤ by increasing the volume and reliability of power, enabling consumers to reduce their reliance on expensive standby generation and making them more willing and able to pay the retail tariffs; and
- ⑤ through structural incentives, for example by reducing the requirement for Governmental support for a national utility's payment obligations under a PSA once the utility achieves cost reflective tariffs and/or increasing the share of any refinancing gain flowing to an Offtaker where the Offtaker is performing well.

PTC India's experience demonstrates that tariff impacts are hard to attribute; however, in sub-Saharan Africa where cost of capital is a key component of project costs, we believe there is scope for a more positive approach. In terms of the direct impact of AGC for utilities, one indicator that we have evaluated is the minimum tariff that would allow a project to be viable ($EIRR > 15\%$) on the basis of lower cost and longer tenor debt. For the first project in the portfolio (Zambia 40MW hydro), a realistic tariff would be in the order of USDc 10/kWh. From a base assumption of 8 year tenor, no interest rate reduction, and 22% equity IRR, the project is un-bankable at that tariff: the breakeven price for 22% EIRR would be USDc 13.2/kWh. Under the optimal AGC impact (15 year tenor, 300bps reduction in cost of debt, and 15% equity IRR) the tariff that makes the project financially feasible falls to USDc 8.6/kWh. The graph below describes the breakeven tariff for different costs of debt and equity.

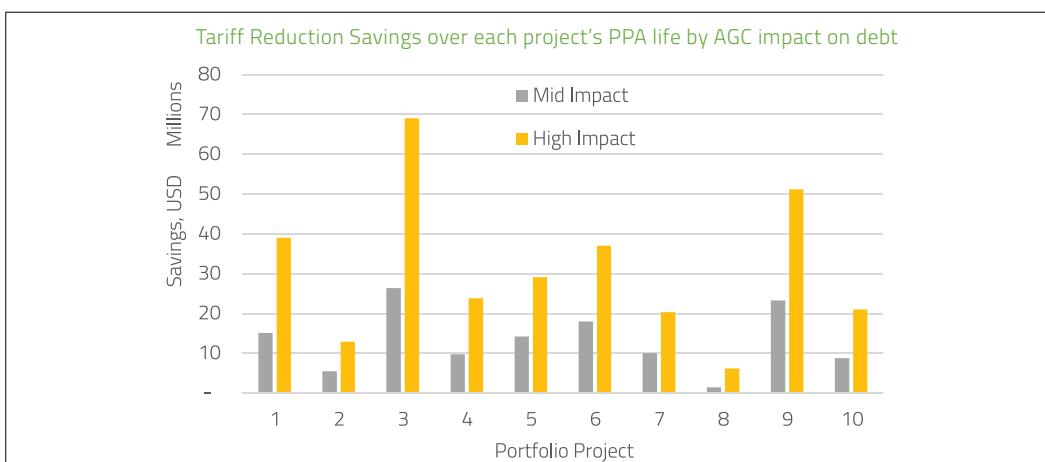


AGC will charge the private developer/investors a margin on the PSA price paid via AGC by utilities. The Generator pays for the benefit of reducing the project's cost of capital; the remainder of the benefit passes through to the Offtaker in the form of lower tariffs. The benchmarks from international best practice for long term PPA margins are opaque – we proposed USDc 0.3/kWh in line with a 3% margin on trading. However, across the portfolio as a whole, AGC has the capacity to generate an average maximum potential savings on tariffs of USDc 1.6/kWh. Taken in the context of efforts to diversify Africa's installed power capacity while keeping costs low, AGC's approach generates a 10-15% lower tariff net of its margin – this impact can be amplified through reductions in equipment and operating costs as seen in the wind and solar sectors.



Assuming that AGC has only half of its potential impact on the cost of capital, the net benefit to utilities after a USDc 0.3/kWh margin would be USDc 0.5/kWh. On the basis of a 25 year PPA, this tariff reduction can generate USD15m savings (mid impact) and up to USD40m savings (max impact) from the Zambian 40MW hydro plant.

“ Across the portfolio this results in USD132m (mid) to USD310m (max) savings; the latter is almost equivalent to the total investment requirement for an AGC model with 33% equity base. For African governments participating in AGC, this potential impact is transformative. Not only in terms of the additional power it will bring to the system, but also in terms of reducing pressure on the sovereign balance sheet. The saving that can be made as a result of tariff reductions, even under the medium impact scenario, is forecast to be greater than the aggregate amount of equity that the financial model assumes will be injected into AGC by Member governments. **”**



Ultimately the scale of this impact varies according to the operating environment (e.g. is less in lower credit risk countries) and project economics (i.e. AGC has a smaller impact for lower cost technologies). However, it is enlightening and positive that AGC can push the needle on tariffs (complementing and enhancing other programs such as GETFiT) and support utilities seeking to move towards cost-reflective end-user tariffs.

6.2.3. Impact on Emergency Power Consumption

Use of emergency power supplies is a growing issue in sub-Saharan Africa, with climatic and economic conditions compounding to push countries into short-term, expensive power sourcing solutions²⁵. AICD data from 2007 estimates that between 5% and 40% of generation was from emergency contracts in some Sub-Saharan countries²⁶, which can add up to substantial expenditure considering the high premium paid for this type of supply²⁷, not to mention carbon emissions.

AGC will reduce member countries' reliance on emergency power contracts by providing additional supply. This additional supply should substitute for current/marginal power needs, at prices substantially lower than those paid for emergency power. The impact on the size of emergency supply requirements can vary, ranging from purely absorbing additional demand (thus avoiding increases in emergency power needs) to meeting additional demand and reducing the emergency power supply contracted. In Kenya, for example, over the period 2005-2012 there were two years where IPP capacity increased: in these years it either kept emergency supply constant by only absorbing additional demand (2008-09), or both absorbed additional demand and replaced a portion of the emergency power supply required in a ratio of 1:0.6 (2009-10)²⁸.

²⁵AFRICA INFRASTRUCTURE COUNTRY DIAGNOSTIC Underpowered: The State of the Power Sector in Sub-Saharan Africa”, Eberhard, Foster et al., 2008

²⁶ Data from AICD accessed 13/05/16, data points only available for Ghana, Kenya, Rwanda, Tanzania and Uganda; however the calculations are in line with those reported by Eberhard, Foster et al. in “AICD Underpowered: The State of the Power Sector in Sub-Saharan Africa”, World Bank, May 2008.

²⁷The cost of emergency power is estimated at USDc 20-30/kWh “Africa’s Infrastructure: A Time for Transformation” V. Foster, 2010, World Bank.

²⁸Assessing the impacts of new IPPs at country level? Case study on Kenya” by Dalberg Global Development Advisors

The economic impact of the additional supply can be substantial. AGC will sell power at an estimated average cost of USDc 12/kWh compared to the USDc 20-30/kWh²⁹ paid for emergency supply. Using a (conservative) ratio of 1 MWh of power purchased through AGC substituting 0.3MWh of emergency power, and using Zambia's emergency power expenditure as an example, the expected savings from purchasing of additional supply through AGC can be calculated as set out below.

In the February 2016 'Ministerial Statement on the Power Situation', the Zambian Ministry of Energy and Water Development announced that, due to the combination of increasing demand and drought conditions in the country, the following emergency power agreements had been contracted:

Emergency Power Contracts in Zambia, 2015-2016

Source	Type	Capacity MW	Contract Period	Tariff (USDc/kWh)
EDM	Hybrid	80-150	Jan 2016- Dec 2017	14.00
Aggreko	LNG	148	Sept - Dec 2015	18.86
Aggreko	LNG	40	Jan 2016 - Dec 2016	18.86
Karpowership	HFO	100	Jan 2016- Dec 2017	16.73
ESKOM	Hybrid	50-300	Jan 2016 - Dec 2016	6 to 19
Total		378-698		

“ Across the portfolio as a whole, the net benefit to all utilities (assuming the same costs for emergency power and rate of substitution) is USD24m each year. ”

The weighted average cost of emergency power for Zambia using the above schedule is about USDc 16/kWh. By purchasing power from a 40MW hydro plant through AGC, Zambia would have access to an additional 192,720MWh of power per year at USDc 10/kWh – i.e. USDc 6/kWh savings. Using the ratio of AGC power purchased to emergency power displaced of 0.3, buying the additional power through AGC would save Zambia in excess of USD3.5m annually. Scaling that up to all four Zambian projects in the portfolio, the possible savings created by AGC through avoided emergency power are USD6.2mm per annum.

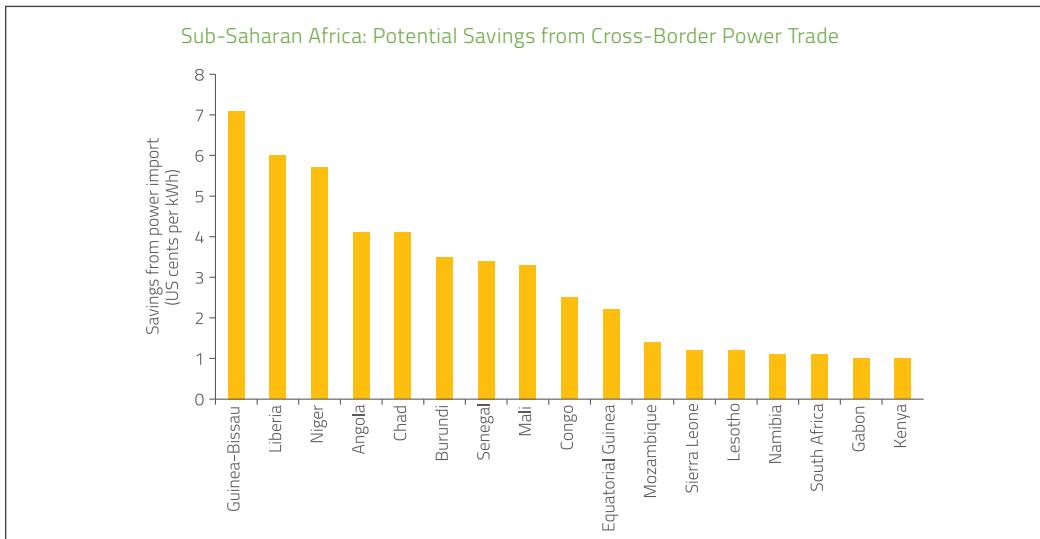
6.2.4. Reducing Tariffs and Increasing Utility Income through Trading

One area where PTC identified a direct value add for utilities was in terms of maximizing the utilization of existing power assets in the system. PTC achieved this by trading power across state borders, where previously the asset either did not produce at full capacity or was non-operating. The utility benefited by increasing its revenues – thereby improving its financial performance and, ultimately, creditworthiness. For SAPP, the challenge is that many countries have been load shedding (especially Zambia) in response to the drought – i.e. they have been deliberately under-utilizing assets to preserve resources. However, load factors for key SAPP member countries preceding the drought – Zambia at 45%, Zimbabwe at 14% - may indicate opportunities for increasing power sales. This is particularly the case for projects in Zimbabwe coming to market now; as a result of ZESA's low creditworthiness and financial capacity, new projects are going directly to cross-border trades to generate cash flows.

Cross border power trade has the potential to considerably reduce electricity costs. Depending on the country and its neighbours, the IMF estimates³⁰ that the cost could be reduced from USDc 10/kWh to USDc 7/kWh by importing power at prices below the domestic cost of production. However, the gains from trade could be much larger, because exporting countries could exploit economies of scale and importing countries would not need to rely on expensive small-scale generators. The potential for trade is large because resources for energy generation are unevenly distributed. Hydropower is mostly in the Democratic Republic of the Congo and Ethiopia; geothermal energy in Kenya, Ethiopia and Djibouti; and wind power potential in Southern Africa. The benefits will be maximised once the power pools are interconnected.

²⁹ Africa's Infrastructure: A Time for Transformation" V. Foster, 2010, World Bank

³⁰Energy Subsidy Reform in Sub-Saharan Africa, Experiences and Lessons (2013) led by Trevor Alleyne.

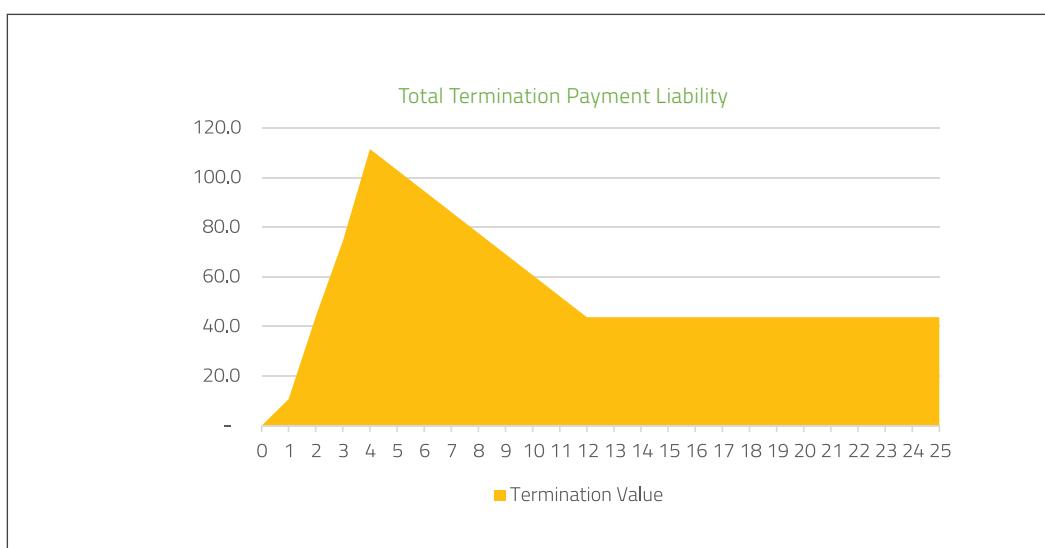


6.3. Sovereign and Macro-economic Impact

6.3.1. Reducing the risk of Government contingent liabilities in respect of PPAs crystallising

One of the main objectives for AGC is to reduce the contingent liabilities assumed by Governments in relation to the power purchase obligations of their national utilities. Details regarding how sovereign guarantees are detrimental to Governments are set out in full in *Section 3.5 (Contingent Liabilities and Debt Sustainability)* above. In summary, for many sub-Saharan countries where national utility companies have low creditworthiness, as is the case with a number of SAPP and other power pool members, it is standard practice for IPP financiers to request Government support for the national utility's payment obligations under its PPAs, whether as a principal obligor or guarantor, to protect against the utility's potential default. These guarantees are recorded on the government balance sheet as a contingent liability – impacting the total levels of public debt, resilience to market shocks and therefore the country's standing in the IMF's Debt Sustainability Analysis.

The impact on the contingent liabilities created over the lifetime of the PPA contract can be substantial. To illustrate the potential magnitude of the impact, the graph below describes the termination value – and therefore the contingent liability created – for the Zambian 40MW hydro project; the liability created peaks at USD100m before decreasing over the life of the contract – but the average exposure is USD65m.



In terms of AGC's impact on contingent liabilities, creating a transaction structure that eliminates an explicit sovereign guarantee and substantially reduces the likelihood of the associated contingent liabilities crystallising may correspondingly reduce the likelihood of the Offtaker's payment obligations under an AGC PSA being recorded in full as contingent liabilities of the sovereign.

Measures to reduce the contingent liability burden that PPAs place on Governments are already in place in the form of World Bank Partial Risk Guarantees (PRGs). To support the expansion of the energy sector in the client countries, IDA and IBRD offer PRGs to commercial investors, which absorb a portion of their downside exposure in the case of a national utility defaulting under a PPA. With the growing level of energy demand in the region, PRGs are in high demand; however it is usually only larger, strategic projects that get access to this support. In respect of each PRG issued, the sovereign is required to provide a counter-guarantee to the World Bank in an amount equal to the value of the PRG, although only 25% of the value of such guarantee is counted against the Government's IDA allocation. However PRGs are not a sustainable solution to the energy shortage in Sub-Saharan Africa and they place material constraints on sovereign finances. Ultimately, Governments have only limited access to project/country specific guarantees from concessional sources and need to find solutions that create scope for private sector guarantees and/or no guarantees.

AGC's capitalisation and membership structure, together with its credit risk mitigation strategies, aims to materially reduce the probability of the Government contingent liabilities associated with PPAs crystallising and reduce the quantum of the Government's contingent liability in relation to payment default by the Offtaker. From the Generator's perspective, there should be no need to look beyond AGC as a creditworthy contractual counterparty under the PPA. This is on the basis that AGC has structured itself and its contractual arrangements in such a way as to mitigate the potential impact of default by any given Offtaker.

AGC's key credit risk mitigants, which reduce the requirement for an explicit sovereign obligation or guarantee in respect of the Offtaker's power purchase obligations, are:

Trading power in case of default	AGC's position as an intermediary offtaker allows it to sell power to alternative buyers in case of offtaker default. From the Generator's perspective, incoming payments from AGC will occur regardless of Offtaker default. If AGC is unable to sell power to an alternative buyer for the same price as the PPA contract or is not able to sell the power at all, AGC will seek to recover such losses from the defaulting Offtaker, initially by applying any payment security provided by the Offtaker.
Capitalisation	If the payment security provided by the Offtaker is exhausted and no alternative long term offtaker has been found and the Offtaker is an SOE, AGC may apply the equity contribution of the host Member state of the defaulting Offtaker in satisfaction of losses suffered by AGC as a result of the default. If this is still insufficient to cover AGC's losses and enable it to continue to make payment when due under the PPA, and it in fact defaults under the PPA and a termination payment becomes due, AGC's capitalisation and guarantee structure means that any applicable termination payment can be made. In the financial model, the full termination exposure across AGC's PPA portfolio is capitalised through equity/leverage for exactly this reason. It is however extremely unlikely that a default would occur under all of AGC PSAs. If AGC has recourse to the sovereign's shareholding in AGC in case of default this creates a secondary contingent liability. However, AGC's operating model and capital structure makes the probability of drawing on that contingent liability minimal. As a result, even if AGC has recourse to sovereigns against defaults under their control, AGC is a highly efficient fiscal management tool from the IMF perspective.
Aligned incentives	Despite the apparent exposure this creates for AGC against termination payments, the strategy of including/requiring beneficiary governments in AGC's capital structure creates added disincentives to default, including: (i) such default will be widely known by the other Members of AGC, including neighbouring countries and MDBs/DFIs, (ii) there could potentially be an impact on any other funding sources provided by the participating MDBs/DFIs to the relevant country and (iii) AGC's financial performance will suffer and the value of that shareholding will be impaired.

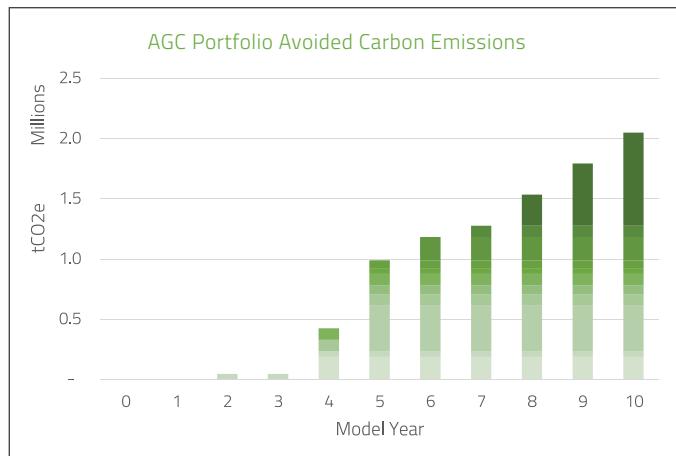
The potential impact of AGC on the extent of PPA-related contingent liabilities on the sovereign balance sheet at the portfolio level ranges from a reduction in liabilities of USD350m in a low impact scenario (25% reduction in reported liabilities) to upwards USD1,050m in the scenario where AGC achieves a 75% reduction in the reported liabilities.

The need for such a structure is highlighted by countries' increasing reluctance to shoulder the risks faced by IPPs. Ghana and Zambia, for example, have announced that they will no longer guarantee small and medium IPP PPAs and, Kenya, Uganda and Nigeria have sought to mitigate their exposure through the World Bank and AfDB PRG schemes.

Through a structure like AGC, the likelihood of contingent liabilities crystallising is substantially decreased, and to the extent this reduces the quantum of contingent liabilities to be recorded on the sovereign balance sheet, creates fiscal space, increases the resilience to economic shocks and increases the Offtaker's capacity to enter into additional PPAs – whether within the AGC portfolio or beyond it.

6.3.2. Environmental Impact

The development impact of AGC can be best seen in terms of the direct environmental and economic benefits resulting from the portfolio projects. Fundamentally, AGC's participation as a creditworthy offtaker for renewable energy greatly increases the chances that renewable energy projects will be financed and built. In terms of carbon abatement, using the CDM grid emissions factors³¹ for each country, AGC's hypothetical portfolio used in the model will avoid 9.3m tCO2e emissions in 10 years and more than 70m tCO2e emissions over the life of the PPAs.



6.3.3. Employment Impact

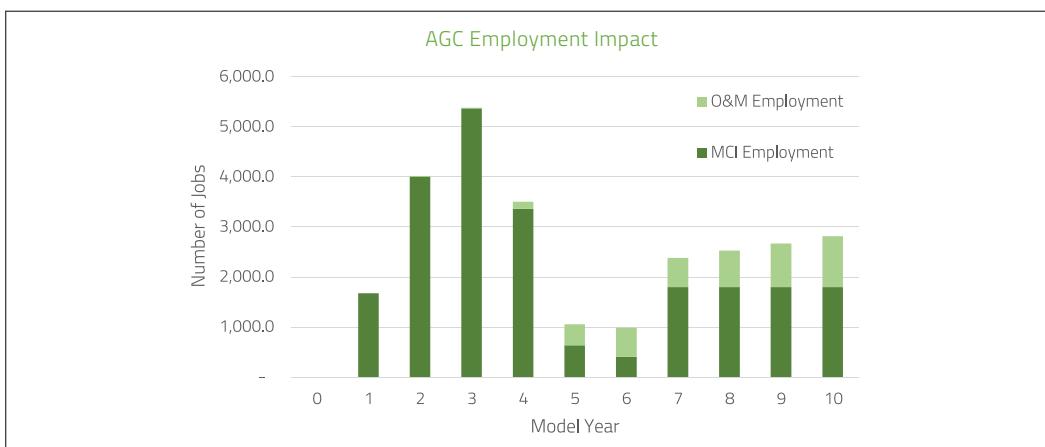
The economic impact of AGC, replicating PIDG metrics, can be seen in terms of short and long-term employment created by the projects in AGC's portfolio. Using IRENA analysis³², we derived technology specific employment rates for each project's construction and operation phases.

Employment Ratios for RE Technologies, IRENA

Technology	Direct Employment	
	MCI/MW	O&M/MW
Hydro - L	30	2.4
Hydro - S	20.3	0.04
Biomass	7.7	5.51
Solar - S	23.7	0.715
Solar - L	23.7	0.715
Wind	16.5	0.61
Geothermal	5.9	1.33

Applying these factors to AGC's portfolio forecasts that AGC will help to create over 22,000 temporary jobs in manufacturing, construction and installation over the first ten years of operations and cover 1000 long term O&M jobs by year 10. This does not include job creation created as businesses in target countries expand due to higher electrification rates, access to more reliable power and savings relative to emergency power consumption. This impact will be most marked in relation to small and medium sized enterprises that cannot afford expensive standby generation, including women's cooperatives. The indirect employment impact will be substantial, but there are few reliable estimates for quantifying the exact scale of the benefit that AGC will generate.

³¹CDM 2013, Standardized baseline: Grid emission factor for the Southern African Power Pool, and country-specific GEFs from UNFCCC
³²IRENA (2016), 'Renewable Energy Benefits: Measuring The Economics'. IRENA, Abu Dhabi.



6.3.4. Social Impact

Improved electricity access will improve access to basic services such as healthcare and education. This is likely to have the greatest impact on the poorest segments of the population and provide particular benefits to women and children, reducing infant and maternal mortality rates and improving employment prospects.

It will also stimulate broader socio-economic development, particularly amongst those who currently have no or very limited access to reliable electricity. Access to electricity will facilitate community-based activities and training.

6.3.5. Cost of outages

The additional capacity obtained by securing supply through AGC will also help to reduce outages, thus potentially boosting economic productivity. Unreliability of supply has been an increasing cause for concern in Sub-Saharan Africa, with countries experiencing an average 100 outages a year in the region³⁴. The implications of the frequency of outages are twofold:

- ① increased use of independent generators (which are expensive and reliant on fossil fuels); and
- ② loss of income due to loss of time and functionality (as well as damage to machinery).

Estimates show that the economic impact of these outages can be as high as 4% of GDP³³ and result in an average annual "drag" on economic growth of 2%³⁵.

By sourcing power through AGC, reliability and predictability of supply should increase, allowing countries to better plan their power dispatch requirements and reducing the cost of outages on the local economy. Increased reliability of the power system can also lead to secondary impacts such as increases in investment, for example by manufacturing firms motivated by the reduced likelihood of black-out losses.

6.3.6. Regional Power Market Development

Aside from the savings incurred within each country due to cheaper, more reliable electricity, there also exist some inherent benefits to regional power trade

³³ World Bank Enterprise Survey Database accessed 16/05/2016, outage counts range from 32 a month for Nigeria (multiple in one day) to just 0.5 per month in Eritrea.

³⁴ Africa Infrastructure Country Diagnostic: Underpowered: The State of the Power Sector in Sub-Saharan Africa", Eberhard, Foster et al., 2008

³⁵ Power Outages and Economic Growth in Africa", T. Barnebeck Andersen and C. Dalgaard, Discussion Papers on Business and Economics No. 7/2012

- ▶ **Increasing market liquidity:** by becoming an active trader in the regional competitive markets, AGC will add its own financial capacity alongside current SAPP members, increasing the volume and value of traded power and identifying strategy opportunities to address geographic or time-bound power deficits/surpluses.
- ▶ **Price efficiency gains:** for countries with a differential across marginal cost of power production, (unrestricted) cross-border trading will adjust the price of power to more efficient levels: resulting in lower prices for net importing countries with high costs of production, and industrial benefits for net exporting countries with lower costs of production³⁶. In Southern Africa, cross-border power trading could deliver an estimated reduction in the levelised cost of energy (LCOE) of approximately 6%³⁷, which could translate into cheaper tariffs for consumers given effective cost pass-through mechanisms.
- ▶ **Savings from coordinated planning:** by coordinating construction of plants, substantial savings can be achieved by countries who struggle to raise the required capital to finance a plant construction project. This occurs either by supporting plant construction elsewhere and relying on power imports, or by justifying construction of the plant with a much larger market (cross-border trading)³⁸.
- ▶ **Revenue from trade:** international experience has highlighted the considerable gains from the sale of electricity in a regionally integrated market, the revenues from the sale of hydropower by Bhutan to India for example now make up a substantial portion of Bhutan's GDP³⁹.

The above benefits are achievable without AGC but AGC can facilitate and support the growth of the market and extend cross-border power trading. AGC will work closely with RERA, SAPP and other relevant organisations and initiatives in order to jointly promote and help implement power sector developments.

6.3.6 Additionally and Complementarity Impact

AGC represents a new vision for stimulating private sector development of renewable energy projects in Sub-Saharan Africa. In contrast with most other initiatives, AGC will be party to the underlying transactions and not merely a provider of financial support. It combines African ownership and political alignment with a strong private-sector oriented commercial management structure which can interface effectively with its contractual counterparties. Once it achieves scale, it will be a self-sustaining, financially viable enterprise in which the initial concessionary funds can be supplemented and/or replaced with commercial debt and/or insurance.

Annex 2 (Additionally and Complementarity Review) provides a detailed comparison of the proposed AGC vehicle with existing initiatives that support low-carbon development in sub-Saharan Africa to reveal the extent to which it is different from (and hence may be considered to be additional to) these initiatives. Its purpose is also to understand how it may complement these other initiatives.

³⁶ Cross border electricity interconnections for a well-functioning EU internal electricity market", A. Jacottet, June 2012, Oxford Energy Note

³⁷ Modelled impact on LCOE in Southern Africa "Brighter Africa The growth potential of the sub-Saharan electricity sector" McKinsey, 2015

³⁸Africa's Power Infrastructure: Investment, Integration, Efficiency", O. Rosnes, M. Shkaratan

³⁹ SAARC Regional Energy Trade Study (SRETS)" http://www.sasec.asia/uploads/publications/srets_a.pdf

7 Contracting Strategy, Risk Allocation and Procurement

This section reviews the main principles underlying AGC's proposed approach to contracting strategy, risk allocation and procurement; analyses the key risks inherent in AGC's sale and purchase of energy, and sets out the proposed allocation of such risks between the principal project parties.

While AGC's role as a regional intermediary could enable it to assume a broad range of risks and seek to manage these on a portfolio basis in order to achieve greater efficiencies than currently present in the market, this could lead to AGC losing focus and/or assuming too many risks and jeopardising its ability to achieve and retain the requisite credit rating to fulfil its primary function as a creditworthy intermediary offtaker. As such the key risks retained by AGC are those which relate to reducing the payment risk borne by Generators and their financiers and reducing the likelihood of the contingent liabilities of the ultimate Offtakers and their host Governments crystallising.

We should not however lose sight of the other benefits of the AGC structure in terms of promoting international best practice throughout the project development, procurement, implementation and operational stages, providing an independent, professional counterparty for both Generators and Offtakers and ensuring an appropriate allocation of risk and reward.

7.1. AGC Contracting Strategy

AGC's contracting strategy can be summarized as follows:

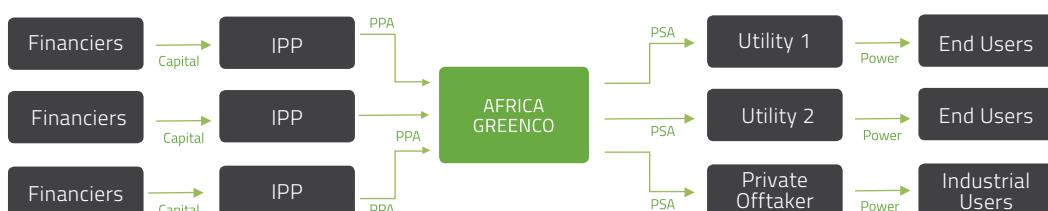
- 1. Start with a bilateral IPP.** The AGC documentation structure (and the risk allocations within that structure) starts with the documentation structure and risk allocations of existing bilateral IPPs as currently executed in SSA today.



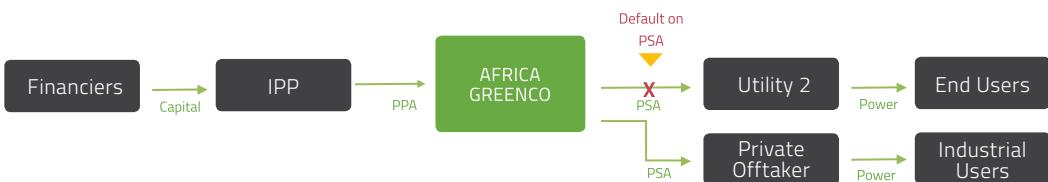
- 2. Interpose AGC** between the Generator and the Offtaker, so that now the Generator sells to AGC, and in turn the Offtaker buys from AGC. The Generator therefore takes credit risk on AGC and AGC takes credit risk on the Offtaker. AGC will continue to pay the Generator even if it is not being paid by the Offtaker.



- 3. Repeat.** AGC will act as an intermediary on multiple projects within each power pool.



- 4. Mitigate.** By building a portfolio of Generators on one side and a portfolio of Offtakers on the other side, AGC will have a much greater ability to mitigate risk than would be possible if those same projects were entered into under concurrent bilateral PPAs. AGC's ultimate credit mitigation strategy is the ability to secure an alternative purchaser if the incumbent Offtaker defaults, whether through its portfolio of other Offtakers or through its trading activities, relying on physically interconnected power transmission infrastructure within the power pool. As it is therefore much less dependent on any single Offtaker, it does not require the power purchase obligations of the Offtaker to be guaranteed.



In the case of Offtaker default, preference will be given to supplying alternative purchasers in the same country as the defaulting Offtaker (for example by selling direct to the customers of the defaulting Offtaker) such that end users are not impacted. The proceeds of sale will offset the defaulting Offtaker's payment obligations to AGC.

As ever, the devil is in the detail and this section seeks to explain the key drivers behind current IPP transaction structures and how the introduction of AGC helps to mitigate the underlying risks, making IPPs more bankable and less onerous for Offtakers and Governments.

7.2. Project finance basics

During the early phases of AGC's implementation, it is expected that most if not all underlying power generation projects will be developed as project-financed IPPs. Project finance is cash flow lending. Lenders lend against contractual promises to pay, not against the underlying value of the project assets or against a balance sheet. The two principal contractual promises to pay are:

- the Offtaker's promise to pay for electrical energy which has been delivered or otherwise made available in accordance with the provisions of the PPA. For most renewable technologies (including solar PV and wind), the tariff is generally calculated on an 'all available energy' or 'energy plus deemed energy'⁴⁰ model at a level expected to be sufficient to cover the cost of servicing the debt raised to finance the construction and operation of the plant and provide an equity return. This reflects the fact that the marginal cost of dispatch is de minimis in contrast to thermal plants where the tariff is generally split into a capacity charge (to cover fixed costs) and an energy charge (to cover fuel and variable operating costs). This Feasibility Study is based upon a single combined tariff; and
 - the Offtaker and/or host Government's promise to pay compensation and/or purchase the project assets (if required to do so by the Generator) upon early termination of the project due to the occurrence of one or more risk events which are either the fault or otherwise the responsibility of the Offtaker and/or host Government.

As lenders are solely reliant on the project cash flows in order to be repaid, they require a high degree of certainty regarding the income stream of the Generator, as well as extensive control over the Generator and its contractual rights and obligations and strong protections in case of default by the Generator, the Offtaker or the host Government. The allocation of risks between the parties is therefore key, and in common with all project finance transactions, each risk associated with carrying out the project should be allocated to the stakeholder which is best able to manage that risk (even if the relevant stakeholder does not absolutely control the risk(s) allocated to it).

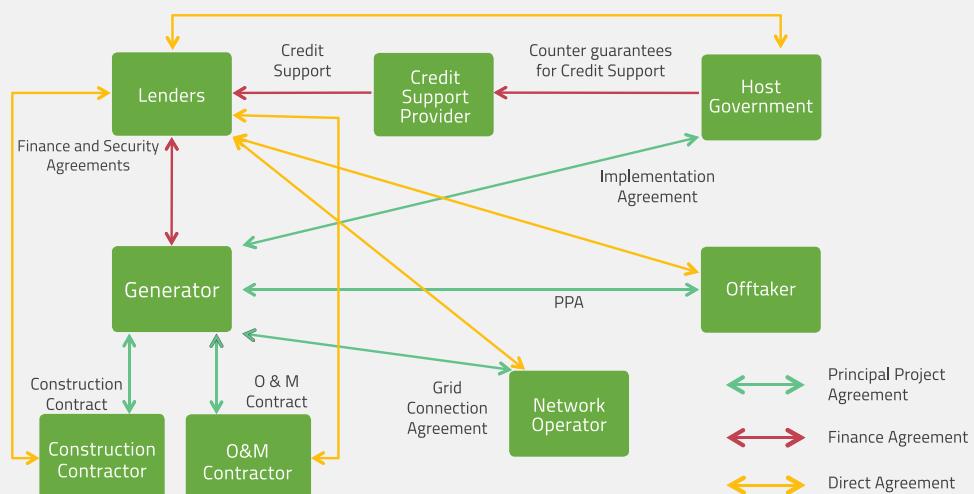
7.3. Overview of typical IPP transaction documents and structure

The principal project documents for a project financed IPP in emerging markets are typically:

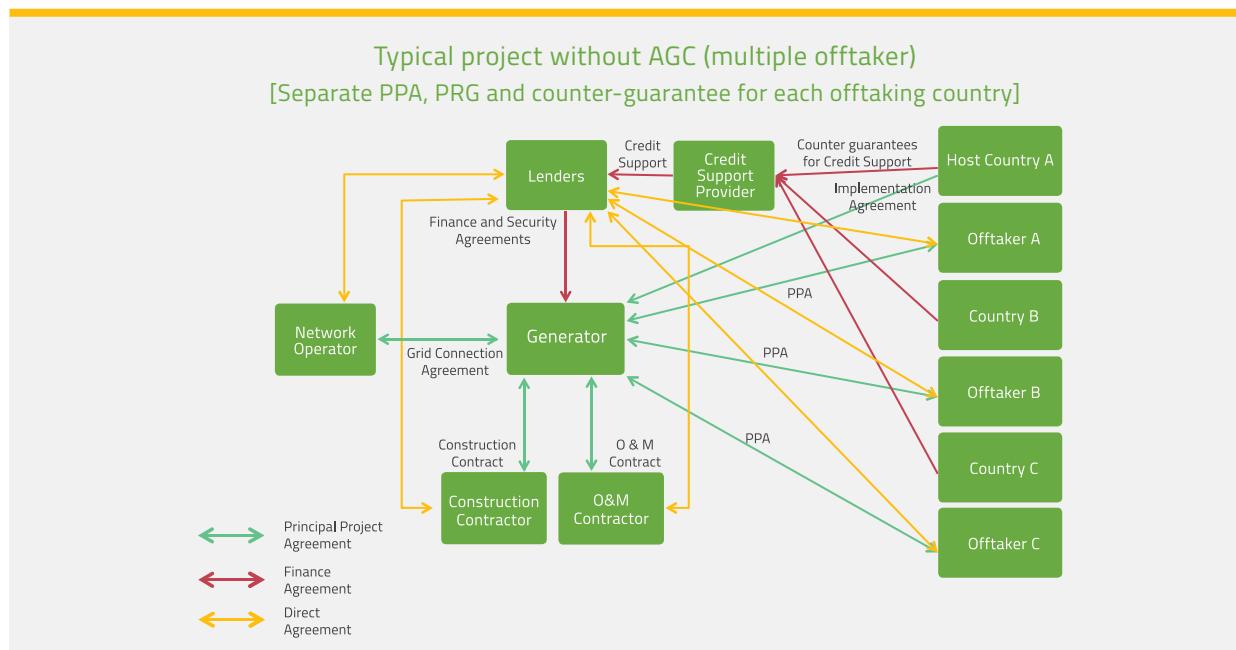
Document	Principal Purpose
Power Purchase Agreement (PPA)	Obligation on Generator to construct and commission the Plant and then on Offtaker to purchase all (or an agreed proportion) of the power generated by the Plant.
Implementation Agreement	Allocation of rights and responsibilities as between Generator and host Government. May contain sovereign guarantee of Offtaker's payment obligations under the PPA.
Liquidity Support Instrument	A letter of credit, bank guarantee or similar in an amount equal to 3-12 months of forecast payments under the PPA which the Generator may draw on immediately upon late payment by the Offtaker.

⁴⁰ 'Deemed energy' is energy which the Generator made available (or could have made available if dispatched) but which was not dispatched by the utility/offtaker.

Credit Support Agreement	Typically a "partial risk guarantee" which will pay if either (a) the Offtaker does not reimburse any payment made by the liquidity support provider and/or (b) the host Government (or Offtaker) does not pay any amount which becomes due under the early termination buyout regime.
Grid Connection Agreement (if applicable)	Agreement between each Generator and non-TSO Offtakers with the relevant TSO to connect to their system.
Wheeling Agreement (if applicable)	Agreement between a TSO and a Generator or third party Offtaker under which the TSO agrees to transmit power across its network to or from the relevant Generator / third party Offtaker.
Inter-Connection Agreement (if applicable)	Agreement between adjacent TSOs to transmit power across their respective systems.
Construction Contract	Contract for the design and construction of the Plant.
O&M Contract	Contract for the operation and maintenance of the Plant.
Facility Agreement	Regulates the advance and repayment of loans, contains covenants (including, financial covenants), undertakings and events of default, and gives the lenders certain controls over the project documents via Reserved Discretions.
Security Agreements	The Generator (and its shareholder(s)) grant security to the lenders over all of the rights and assets of the Generator such that the lenders can take control of the Project in case of default.
Direct Agreements (with respect to all key project documents including PPA, Implementation Agreement, Construction Contract, O&M Contract and Grid Connection Agreement)	Agreement between the Generator, the relevant counterparty and the lenders under which the counterparty agrees not to enforce its rights to terminate the relevant project document for Generator Default without first giving the lenders the opportunity to step in and remedy the Default and/or replace the Generator.



Where there are multiple Offtakers for a single project, particularly where they are based in different countries, the Generator will need to negotiate multiple PPAs and (where required) Credit Support Agreements with (or in respect of) each Offtaker, together with corresponding Direct Agreements. This is shown below.



Introducing AGC as a counterparty to the Generator dispenses with the need for the Generator to enter into multiple PPAs and associated Credit Support Agreements.

7.4. AGC as an intermediary offtaker

Starting with a typical IPP structure, it is proposed that AGC is interposed between the Generator and the Offtaker. As a result, AGC will become the purchaser under each Generator's PPA and on-sell power under PSAs with Offtakers.

AGC's proposed contractual structure will:

- (a) simplify the contractual relationships (and associated negotiation processes) for the Generator and thereby facilitate multi-Offtaker transactions, diversifying and mitigating risk for all parties; and
- (b) reduce the risk of PPAs being terminated due to payment default and early termination compensation/buyout amounts becoming payable by the host Governments, whether as principal obligor under the early termination buyout regime and/or as guarantor.

Save as set out above, the inclusion of AGC in the project structure will not change the fundamental allocation of risks to the Generator or the Offtaker.

As AGC's primary role within this structure is to act as an intermediary Offtaker, its key contractual relationships will be:

- (a) the PPAs it enters into with Generators;
- (b) the PSAs it enters into with Offtakers;
- (c) the Government support arrangements it enters into with host Governments; and
- (d) (if applicable), the wheeling agreements it enters into with TSOs.

These are considered in more detail below.

7.5. Key principles influencing the allocation of risks in AGC's PPAs and PSAs

When structuring the PPAs and PSAs it is important to ensure that:

- a. the PPA is sufficiently robust to facilitate the Generator's ability to raise project finance debt from commercial lenders;
- b. AGC does not become the repository for undue risks, which would impair its creditworthiness and result in the model being unsustainable. AGC will be sufficiently well capitalised to ensure it is able to continue honouring its payment obligations under PPAs while taking steps to remedy an Offtaker default. Careful consideration should however be given to whether AGC should assume risks it has no ability to mitigate, such as Political Force Majeure Events (see *Section 7.6 (Allocation of key risks in AGC's PPAs and PSAs)* and *Annex 1 (Detailed Allocation of Key Risks in PPAs and PSAs)*);
- c. to the extent AGC does retain risks, it should have clear strategies for mitigating these risks;
- d. the likelihood of crystallisation (and in some cases, quantum) of the contingent liabilities assumed by Governments in respect of the power purchase obligations of their national utilities is reduced; and
- e. the Offtakers and their host Member states are sufficiently incentivized to perform their obligations under the PSAs.

In deriving AGC's proposed risk allocation structures, we have looked at current practice regarding risk allocation in sub-Saharan Africa, including South Africa, Uganda and Zambia and drawn on the experience of PTC India⁴¹, the Southern California Public Power Authority and the Nigerian Bulk Electricity Trading Plc as working examples of entities provide services similar to those which AGC will provide⁴². Please refer to *Section 2 (Precedent for Power Sector Intermediary - PTC India)* above for a detailed overview of PTC India and *Annex 9 (Other Precedents for Bulk Power Purchasers)* for an overview of the Southern California Public Power Authority and the Nigerian Bulk Electricity Trader.

7.6. Allocation of key risks in AGC's PPAs and PSAs

The table in *Annex 1 (Detailed Allocation of Key Risks in PPAs and PSAs)* sets out the allocation of key risks within the AGC transaction structure between:

- a. Generator and AGC under a PPA; and
- b. AGC and Offtakers under a PSA.

In most respects, AGC acts as an intermediary and the obligations and liabilities of the Generator and Offtaker flow through AGC. AGC's main role is when it comes to the mitigation of credit risk. Through its structure, AGC has the contractual and operational ability to secure one or more alternative buyers if an incumbent Offtaker defaults. For the Generator, this reduces the likelihood that it will have to exercise the early termination buyout regime, which in practice is a 'last resort' option. For the host Government it reduces the likelihood that very significant liabilities under the early termination buyout regime will crystallise.

A summary of these risks is set out in the table below.

⁴¹ See www.ptcindia.com

⁴² The contractual structure discussed here applies to long-term offtake arrangements with AGC as the intermediary between an IPP and multiple power purchasers. As discussed elsewhere in this report, AGC will also trade power pursuant to established trading regimes for short-term power supply in markets, such as SAPP, where such trading regimes have been established. Such markets operate on uniform, established terms of trade and we do not address those terms in this section.

Risk Category	Risk Allocation between Generator and AGC under the PPA	Risk Allocation between Offtaker and AGC under the PSA
1. Availability and suitability of source energy	Under an 'all energy' tariff model (as typically used on renewable independent power projects in Sub-Saharan Africa), the Generator is only paid for electrical energy which it delivers (or is deemed to have made available), and in this sense the Generator bears the risk regarding its ability to generate power based on the adequacy and suitability of the supply of source energy.	The Offtaker only pays for electrical energy which AGC delivers to the Offtaker or which AGC is deemed to have made available to the Offtaker. To mitigate a situation where the Offtaker is contracted to purchase more power than it needs or can afford, the PSA will include a right for the Offtaker to request AGC to find an alternative purchaser for power. If the volume of power generated is less than expected, the Offtaker may request AGC to source power from an alternative source.
2. Site acquisition	<p>The respective responsibilities in relation to Site acquisition will depend on the underlying circumstances of each individual Project.</p> <p>In practice, it is expected that in most cases the Generator will be responsible for acquiring ownership or a long lease of the Site.</p>	Unless expressly agreed otherwise on a case-by-case basis, neither AGC nor the Offtaker have any responsibility in relation to Site acquisition.
3. Construction Risk	As between AGC and the Generator, the Generator is solely responsible for the design and construction of the Plant, and attaining COD 'on time'. The Generator will be liable for delay liquidated damages if COD is delayed beyond the scheduled date.	The construction related obligations in the PSA will be back-to-back with the PPA, but with longer periods under the PSA to allow AGC an opportunity to remedy the Generator's default and/or source alternative power to satisfy its obligations under the PSA.
4. Permitting Risk	The Generator must duly and properly apply for all necessary permits, but will be given relief to the extent that the issue of such permits is delayed or not forthcoming due to the failings / default of a Government Agency or AGC.	Back-to-back with the PPA.
5. Decommissioning	The decommissioning obligations will usually be contained in the permits obtained by the Generator in relation to the site. To the extent AGC has decommissioning obligations under the PSA, these will be passed through to the Generator on a back-to-back basis.	Back-to-back with the PPA (if applicable).
6. Performance Risk	<p>The Generator will be subject to performance ratio and/or availability targets (in practice depending on the generation technology), and associated liquidated damages.</p> <p>Prolonged failure to attain such targets will ultimately lead to a Generator Event of Default and subsequently a right of AGC to terminate the PPA for Generator 'fault'.</p>	Back-to-back with the PPA, save that if the Generator fails to deliver power, AGC may, but is not obliged to, procure power from alternative sources and deliver such power to the Offtaker(s) in lieu of the contracted power and otherwise on the terms and conditions set out in the PSA.
7. Exchange Rate Risk	The tariff will be denominated in the same currency as the Generator's primary source of funding (usually USD) but may be paid in local currency at the prevailing buy rate for each payment period.	<p>Unless and until AGC puts a hedging regime in place, the currency provisions in the PPA will be reflected on back-to-back terms in the corresponding PSA(s). For further commentary please refer to Section 5.9 (Foreign Currency Exchange Risk).</p> <p>(NB, where the Offtaker is in a different country to the Generator, 'local currency' will mean the Generator's local currency.)</p>
8. Payment terms	<p>Monthly billing cycles with a 7 day buffer between the due date under the PSA and under the corresponding due date under the PPA to allow AGC time to process payments received from Offtakers.</p> <p>Late payment will trigger default interest at [USD LIBOR +X%] per annum, albeit AGC intends to always pay on time and as such default interest should never arise under the PPA even if it arises under the PSA.</p>	<p>AGC will seek to secure short billing periods of between 7 and 30 days with payment periods of 30-60 days depending on the track record and creditworthiness of the Offtaker to enable AGC to minimize credit exposure to the Offtaker and the impact of any potential payment default.</p> <p>Default interest provisions will apply in order to incentivize timely payment. A payment delay under the PSA will not lead to a corresponding payment</p>

Risk Category	Risk Allocation between Generator and AGC under the PPA	Risk Allocation between Offtaker and AGC under the PSA
8. Payment terms (Continued)		delay under the PPA, and the default interest rate under the PSA does not therefore need to be the same as the rate under the PPA, but should be set at a level to reflect at least any cost to AGC arising as a result of "curing" such late payment.
9. Liquidity Support	<p>No liquidity support provided by AGC to the Generator as AGC is itself sufficiently creditworthy.</p> <p>The Generator will be obliged to provide a performance bond to back its obligation to pay delay liquidated damages.</p>	AGC will be sufficiently well-capitalized to continue making payments under the PPA even if there is a payment default under the PSA and is therefore less dependent on liquidity support from the Offtaker. However, it still has an interest in mitigating its credit exposure to the Offtaker and incentivizing timely payment. Feedback received indicates a majority view that liquidity support should still be required from the Offtakers in order to both reduce AGC's credit exposure and act as an early warning prior to triggering payment default. If liquidity support is still required, it is likely to be of a lower quantum than currently required, and result in a lower fiscal impact on the Offtaker.
10. Convertibility and repatriation of funds	<p>The Generator will require protection with regard to the convertibility and repatriation of funds, which can only be provided by the host Government, either directly (the "Direct Approach") or via AGC (the "Flow Through Approach"). Please refer to <i>Section 7.10 (Flow Through Approach v Direct Approach)</i> below for further details.</p>	Cross-termination of the PSA with any related Offtaker of the defaulting Government upon termination of the agreement(s) with the host Government for Government default. AGC will be entitled to terminate any PSAs with other Offtakers and this would be treated as Non-Political Force Majeure under such PSAs. Please see row 14 (Force Majeure Affecting Offtakers) for further details.
11. Availability of finance	<p>Generator bears the full risk on its ability to source adequate debt and equity funding and may be obliged to provide a bid bond which can be called by AGC if it fails to achieve financial close within the requisite time period.</p>	Proceeds of bid bond retained by the entity responsible for procurement.
12. Change in Law / Tax - economic stabilisation and Government Event of Default	<p>With limited exceptions, e.g. changes in domestic law which merely bring domestic law up to existing international standards, the Generator and its Lenders will not take Change in Law/Tax risk above an agreed 'de minimis' threshold.</p>	<p>Where the Offtaker is the national utility of the country whose Government instructed the change in law / tax, that Offtaker may:</p> <ul style="list-style-type: none"> a. bear the full impact of the Tariff change, unless and until the Government has paid the compensation due under the relevant Government support arrangements (please refer to <i>Section 7.8 (Contractual relations with Governments)</i> below), although some utilities have historically rejected taking on risk/responsibility for Government 'fault'; and b. seek to pass through the increased costs to end users (which would require the relevant Regulator to approve an increase in the end user tariffs). <p>Where the Offtaker is not a national utility:</p> <ul style="list-style-type: none"> a. the tariff paid by the Offtaker will not change; and b. either: <ul style="list-style-type: none"> i. under the Direct Approach, AGC is not involved and the Generator will need to seek compensation directly from the relevant host Government; or ii. under the Flow Through Approach, (A) a mismatch will arise between the tariff received by AGC from the Offtaker and the tariff increase and/or lump sum payable by AGC to the Generator, and (B) AGC will need to recover the difference under its Shareholders Agreement or Establishment Treaty/ Participation Agreement with the relevant host Government (for further details please refer to <i>Section 7.8.2 (Project Structure with AGC)</i> below).

Risk Category	Risk Allocation between Generator and AGC under the PPA	Risk Allocation between Offtaker and AGC under the PSA
13. Force Majeure affecting Generator	<p>Generator Relief From Obligations The Generator will be relieved from its obligations under the PPA to the extent it is not able to perform those obligations as a result of a Force Majeure Event ("FME") affecting it or its subcontractors.</p> <p>Termination for Prolonged FME Either party has the right to terminate for prolonged FME.</p> <p>Compensation: Local Political FME AGC will owe the Generator compensation and seek to recover this from the host Government under the Flow-Through Approach or the host Government will owe the Generator compensation directly under the Direct Approach.</p> <p>Prior to termination: Pre-COD, compensation to cover the Generator's increased costs and/or lost revenue. Post COD and prior to termination of the PPA, the compensation amount will be calculated in the same way as deemed energy payments.</p> <p>Upon termination: The buy-out price under the resulting put option will be the same as for Government default.</p> <p>Compensation: Foreign Political FME and Non-Political FME Prior to termination: no compensation is payable. Upon termination: The buy-out price under the resulting call option will be the 'no fault' purchase price.</p>	Flow through from the PPA to the PSA on a back-to-back basis.
14. Force Majeure affecting Offtakers	<p>Back-to back with the PSA in relation to the proportion of the power sold under that PSA, save that where AGC is excused from paying deemed energy charges as a result of Non-Political or Foreign Political FMEs affecting a Non-TSO Offtaker:</p> <ul style="list-style-type: none"> a. AGC will use reasonable endeavours to continue to take energy from the Generator and sell it to one or more third party customers, in which case the revenue received (less a small 'service charge' retained by AGC) will be payable to the Generator; and b. (to be discussed), if the relevant event occurs in a country other than the Generator's host country but which is also an AGC member, whether the Government of the country in which the event occurred should bear liability under the AGC Establishment Treaty / Participation Agreement, in which case such payments would be passed through to the Generator. 	<p>All FMEs affecting TSO Offtakers: The Offtaker's obligations to pay for electrical energy delivered by AGC and/or for deemed energy are not excused for FMEs affecting the TSO, save that an annual excused grid unavailability threshold may apply (to be discussed).</p> <p>Local Political FMEs affecting Non-TSO Offtakers: The Offtaker's obligation to pay AGC for delivered and/or deemed energy is not excused but should be passed through to the host Government either through the Direct Approach or the Flow Through Approach (see <i>Section 7.9 (Flow Through Approach v Direct Approach)</i>).</p> <p>In all cases where deemed energy payments become payable by the Offtaker as a result of an FME, AGC will use reasonable endeavours to continue to take energy from the Generator and sell it to one or more third party customers, in which case the revenue received (less a small 'service charge' retained by AGC) will be credited to the Offtaker and offset against any such deemed energy payments.</p> <p>Non-Political and Foreign Political FMEs affecting Non-TSO Offtakers</p> <p>To be further discussed whether the Offtakers will be excused from paying deemed energy charges or will be expected to hold business interruption insurance and claim under it.</p> <p>If a right to terminate for prolonged FME arises, but such FME does not prevent the Generator from operating or exporting, AGC may terminate the PSA and use reasonable endeavours to secure an alternative purchaser in order to preserve the PPA.</p>

Risk Category	Risk Allocation between Generator and AGC under the PPA	Risk Allocation between Offtaker and AGC under the PSA
15. Force Majeure Affecting AGC	AGC excused from its obligations, although as AGC's principal obligation is the obligation to pay for power delivered, and it does not own the transmission infrastructure or undertake any physical activities, AGC is highly unlikely to be affected by Force Majeure.	AGC excused from its obligations although as AGC's principal obligation is the obligation to sell power, and it does not own the transmission infrastructure or undertake any physical activities, AGC is highly unlikely to be affected by Force Majeure.
16. Generator Events of Default	Customary Events of Default. Please refer to Annex 1 (Detailed Allocation of Key Risks in PPAs and PSAs) for further details.	Right to terminate the PSA if AGC fails to provide power for a period of [14] days beyond the first date on which AGC could have terminated the PPA as a consequence of the underlying event. This gives AGC some time to source alternative power to cure the default and preserve the PSA.
17. AGC / Offtaker Event of Default	<p>Customary Events of Default including:</p> <ol style="list-style-type: none"> 1. Failure to pay any amount due to the Generator within [45-60] days after receipt of notice that such payment is overdue; 2. Insolvency Events; 3. Material breach; 4. Failure to complete any necessary grid improvement works by the longstop date (unless they are works of a nature AGC or the Generator could do and opts to undertake in order to cure such breach); 5. Assignment of the PPA in breach of restrictions; 6. Change in Law that: <ul style="list-style-type: none"> a. renders a material undertaking of offtaker void or unenforceable; b. renders a material right of the Generator void or unenforceable; or c. restricts repatriation of dividends or the payment of loans, in each case for a period of [90 – 180] days; and 7. Offtaker Event of Default or Government Event of Default under another Project Agreement. 	<p>Back-to-back with the PPA with appropriate time buffers. Additional Offtaker Event of Default for failure to provide / replenish / replace any requisite liquidity support.</p> <p>In the event of an Offtaker Event of Default arising under the PSA, AGC is not excused from its obligations under the corresponding PPA. Accordingly, vis-à-vis the Generator, AGC takes Offtaker performance risk and importantly Offtaker (or host Government) credit risk in relation to any early termination buyout payment obligations which may arise under the PSA or associated Government support arrangements (please refer to Section 7.8 (Contractual relations with Governments) below). While AGC will require a strong capital base to enable AGC to bear this risk, in practice, AGC will mitigate this risk by seeking to find one or more alternative sale routes for the power, whether through securing alternative long-term offtakers and/or selling the surplus power on the market.</p>
18. Termination Event	Generator may terminate for AGC Event of Default (subject to cure periods). AGC may terminate for Generator Event of Default (subject to cure periods and funder rights under the PPA Direct Agreement). Either party may terminate for prolonged (180 days) FMEs.	AGC may terminate for Offtaker Event of Default (subject to cure periods). Offtaker may terminate for AGC Event of Default (subject to cure periods). Either party may terminate for prolonged (180 days) FMEs.

Risk Category	Risk Allocation between Generator and AGC under the PPA	Risk Allocation between Offtaker and AGC under the PSA
19. Early Termination Payment	<p>The early termination amount payable to the Seller will depend on the reason for termination.</p> <p>AGC / Offtaker Event of Default</p> <p>If the Generator exercises its put option, the purchase price shall be:</p> <ol style="list-style-type: none"> 1. Outstanding debt obligations. 2. Repayment of outstanding equity 3. Return on equity for an agreed period discounted to net present value at a rate to be discussed/agreed (to cover a sufficient period to allow investors to reallocate funds). 4. Termination and transfer costs. <p>Local Political Force Majeure</p> <p>If the Generator exercises its put option, the purchase price shall be the same as for Offtaker Event of Default less any insurance proceeds.</p> <p>Non-Political Force Majeure and Foreign Political Force Majeure.</p> <p>If AGC exercises its call option, the purchase price shall be</p> <ol style="list-style-type: none"> 1. Outstanding debt obligations. 2. Termination and transfer costs. Less 3. Insurance proceeds. <p>Generator Event of Default</p> <p>No early termination payment due unless AGC exercises its call option.</p> <p>If AGC exercises its call option, the purchase price shall be:</p> <ol style="list-style-type: none"> 1. Outstanding debt obligations. 2. Termination and transfer costs. Less 3. Outstanding equity commitments (i.e., funding which the Generator's shareholders have committed to provide to the Generator but have not yet provided). 	<p>Offtaker Event of Default</p> <p>If a PSA is terminated for Offtaker default, the termination payment due to AGC under the terminated PSA will be equal to [2 years of forecast energy payment under such PSA]^[TBD]. This allows AGC a 2 year buffer to find an alternative purchaser for the power. The Generator will continue generating capacity in accordance with AGC's despatch instructions and sell all power to AGC, which will in turn sell any surplus power in the market in the meantime, so 2 years' of revenues should in practice cover a longer period than 2 years.</p> <p>Local Political Force Majeure:</p> <p>(a) if there is a single Offtaker, Local Political Force Majeure will be solely attributable to it and therefore the early termination amount payable (as calculated in accordance with the previous column) will be a straight pass through.</p> <p>(b) where (i) a single PPA is matched to multiple PSAs, and (ii) the act of a single Offtaker (or its Government) triggers a Local Political Force Majeure in respect of the whole of the PPA, the early termination buyout regime in relation to that Offtaker and/or Government will apply in respect of the whole of the Plant. This will be deemed to be Foreign Political Force Majeure under any PSAs with Offtakers in other countries but without any further obligation on either party upon such termination.</p> <p>Non-Political Force Majeure and Foreign Political Force Majeure</p> <p>The early termination payment will be divided pro rata between the Offtakers (or their host Governments) who will receive a pro rata share of the purchased Plant.</p> <p>AGC Event of Default</p> <p>No early termination payment unless an Offtaker opts to purchase the Plant, in which case the purchase price will be back-to-back with the PPA.</p>

7.7. Grid connection and wheeling arrangements

7.7.1. Typical IPP grid connection and wheeling arrangements without AGC

In many sub-Saharan African countries, the Offtaker is often the domestic TSO. In this case, grid connection is often dealt with contractually within the PPA but it may be preferable to be dealt with in a separate Grid Connection Agreement in order that the associated grid connection and wheeling rights survive any termination of the PPA and/or unbundling of the electricity market and separation of roles of the Offtaker and TSO. As AGC will be the contractual counterparty of the public sector parties, it can help to insulate the Generator against any legal and regulatory disruption during any such unbundling process.

Under a PPA, risk in the power passes at the agreed delivery point. Where the Offtaker is the domestic TSO, this is generally at the point at which the Generator's Plant connects with the TSO's system. If the Offtaker is not the domestic TSO, then arrangements are required to:

- ④ permit both the Generator and the Offtaker to connect to the domestic TSO's infrastructure ⁴³;
- ④ remunerate the domestic TSO for transmitting (or "wheeling") power from the Generator to the Offtaker; and

⁴³ This may be wholly or partially catered for by the Grid Code.

- ⑤ allocate the risk of losses arising between the point at which the Generator exports power onto the TSO's system and the point at which the Offtaker imports power from the TSO's network.

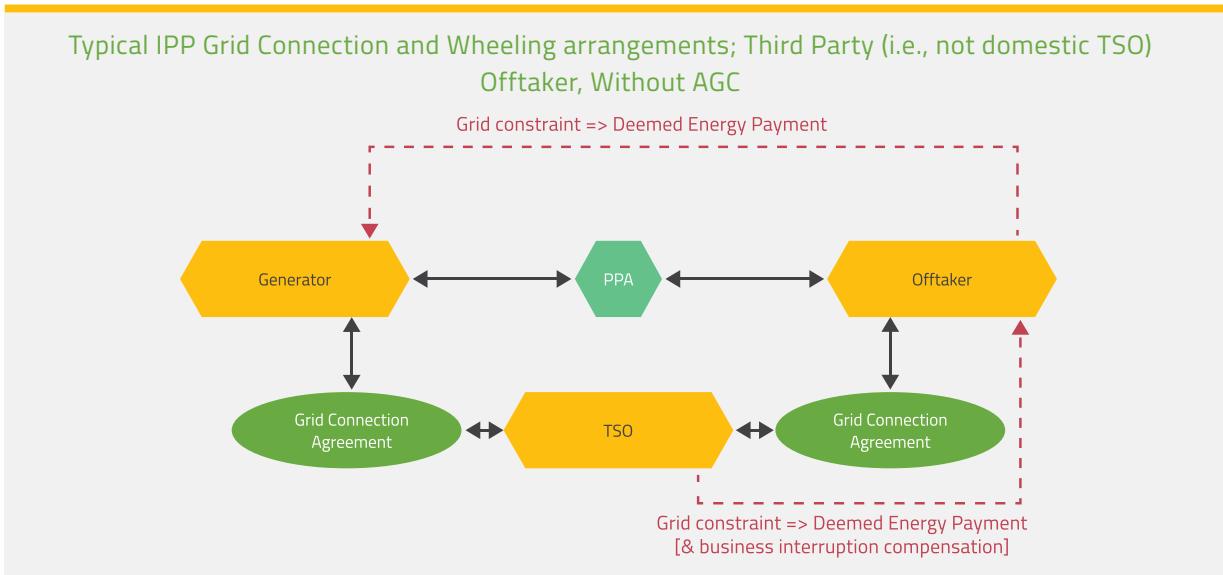
Where the Offtaker is not the domestic TSO:

- ⑥ the Generator will prefer the PPA delivery point to be the point of connection between the Generator's Plant and the TSO's system, in which case:
 - it will be the Offtaker's responsibility to enter into arrangements with the TSO for wheeling power from the Generator to the Offtaker; and
 - accordingly, as between the Generator and the Offtaker, 'grid risk' will be allocated to the Offtaker, and the Offtaker may or may not be able to transfer (all or part of) this risk to the TSO; however,
- ⑦ the Offtaker will prefer the PPA delivery point to be the point of connection between the Offtaker's facilities and the TSO's system, in which case (a) the obligation to contract with the TSO, and (b) the allocation of grid risk as between the Generator and the Offtaker, lie with the Generator;

if (and for so long as) the TSO's system fails:

- ⑧ subject to the 'excused grid unavailability' regime (if any), for project finance purposes the Generator should receive payment for 'deemed energy'; i.e., energy which the Generator could have delivered but for the grid failure; and
- ⑨ the Offtaker may also suffer business interruption costs associated with the non-delivery of power; however, typically the TSO will not compensate the Offtaker for these costs.

In the event of TSO system failure, one potential mitigation strategy is the Generator (a) selling to the domestic TSO, but (b) physically connecting to a local distribution company; however, this is a situation which may be dealt with as and when it arises and is not included in the discussion below.

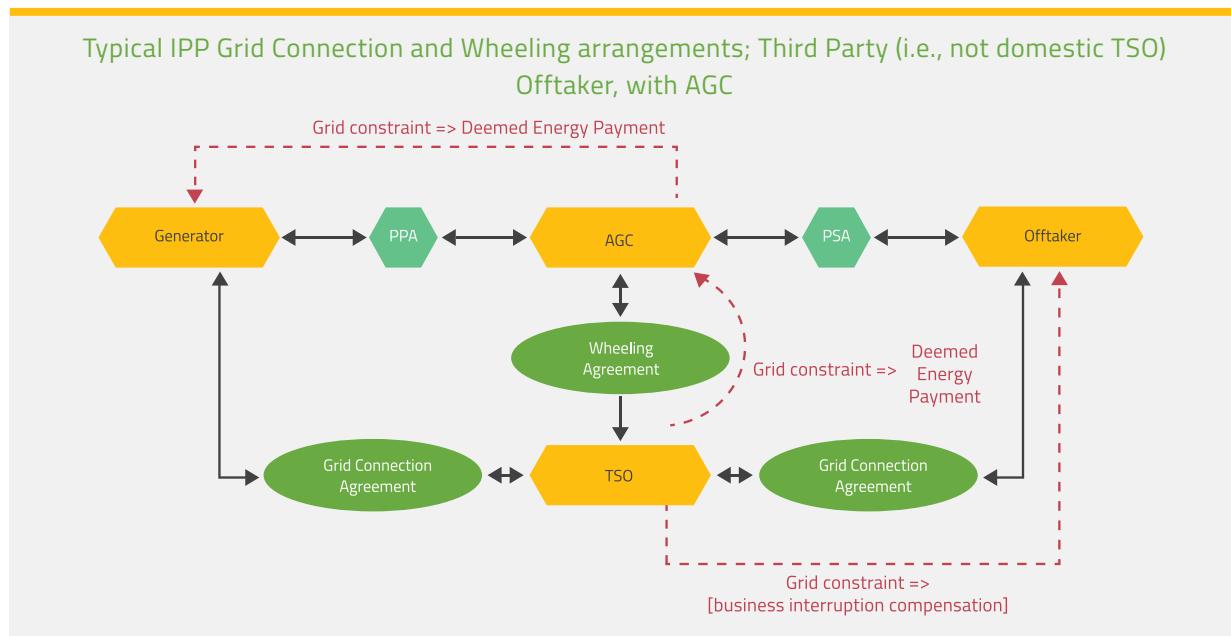


7.7.2. Typical IPP grid connection and wheeling arrangements with AGC

When AGC is interposed between the Generator and the Offtaker, the PPA/PSA delivery point may be the same as in the structure without AGC – i.e. the Offtaker may still take risk under the PSA from the point at which the Generator delivers power, whether at the point of connection between the Generator's Plant and the grid or the Offtaker's system and the Grid. In this arrangement, the transmission risk remains with the Generator or Offtaker, as above.

Alternatively AGC may agree to take delivery of power under a PPA at a different point to the point at which it delivers power under a PSA. In such event:

- ⑤ both the Generator and the Offtaker will need an arrangement (assumed for these purposes to be a Grid Connection Agreement) which allows them to connect to the TSO's infrastructure (assuming that the Offtaker is not the TSO);
- ⑥ AGC will enter into a Wheeling Agreement with the TSO; and
- ⑦ to the extent that one or more grid constraints (or grid failures, etc.) gives rise to an obligation to make deemed energy payments, AGC will (a) owe the deemed energy payments to the Generator, and (b) seek to recover the relevant amount from the TSO. Accordingly, AGC will take credit and payment risk on the TSO in respect of such payments.



Under such arrangements, AGC would retain the right (and a reasonable efforts obligation) in certain circumstances to divert power from the Generator to alternative Offtakers (if any) who are not affected by the relevant grid constraint.

AGC does not intend to assume transmission risk and, as noted above, will achieve this by specifying that the delivery point for power under the PPA is the same physical point on the grid as the delivery point under the PSA. Even if AGC does not take the transmission risk between the delivery point and the offtake point, AGC will still enter into wheeling agreements with each TSO within its member states (and potentially the whole region) in order to facilitate its trading activities and to provide the maximum potential sale routes in case of default by an Offtaker. In the case of grid failure, AGC will also use reasonable endeavours to find an alternative sale route for the power affected.

7.7.3. Responsibility for transmission losses

In a power system, technical and non-technical losses can occur at various stages of production, transmission, distribution and supply. Technical losses arise from equipment consuming some of the energy generated due to their characteristics e.g. losses occur in generators and transformers as a result of heating of the copper components, magnetisation of the iron cores and corona effects within insulation materials.

Losses on wheeling transactions are physically compensated by the wheeling party such that the recipient receives the same volume of power as it purchases, but the wheeling party is financially compensated by the users based on generation or market prices. SAPP has comprehensive rules and methodologies for both wheeling and loss compensation. Currently in SAPP the rules require both the seller and the purchaser to bear each 50% of the loss compensation based on the market clearing price for the day ahead market. However, this position may be modified contractually between buyer and seller and in practice, the pricing is often adjusted such that the offtaker bears the full cost of such transmission losses and in some cases, the compensation is calculated based on the actual cost of generation by the wheeling party. As AGC does not intend to assume transmission risk, any costs associated with transmission will be dealt with on a straight pass-through basis to the Generator and the Offtaker as appropriate.

7.8. Contractual relations with Governments

7.8.1. Typical IPP structure without AGC

As the Generator's sole source of operating revenue derives from the PPA, both the Generator and its lenders must satisfy themselves as to various practical considerations, including *inter alia* the Generator's ability to:

- obtain (and renew) all necessary consents to build and operate the plant;
- convert domestic currency into foreign currency and vice versa without restriction and at a market rate of exchange; and
- repatriate funds earned in the host country to foreign investors and lenders.

In addition:

- various risks which the host Government is best able to manage should be contractually allocated to the host Government; and
- as the Offtaker is usually not considered sufficiently financially robust to meet the contingent early termination buyout obligation (should it arise), the early termination buyout obligation is usually entered into with the host Government (as opposed to with the Offtaker)⁴⁴.

Accordingly, in addition to the PPA with the Offtaker, the Generator will typically enter into a contract with the host Government. Depending on the country involved, this may be called an "Implementation Agreement", "Concession Agreement", "Concession and Implementation Agreement", "Government Consent and Support Agreement", "Government Support Letter", etc. Regardless of the name, each of these would generally include obligations on the host Government to:

- ▶ assist in the grant of necessary permits and consents ("Permits"), and ultimately to bear the risk of non-issue and/or non-renewal of Permits provided that the Generator has done everything it should in seeking the issue or renewal of requisite permits and consents;
- ▶ ensure that source energy is not impeded by man-made factors within the control of the host country, e.g., in the case of hydro, by upstream irrigation or water diversion projects;
- ▶ where appropriate/required, grant or procure the grant of any necessary land rights and/or assist in any requisite land expropriation;
- ▶ procure any necessary grid improvements;
- ▶ assist in obtaining any necessary import licences, expedite the customs clearance of any materials or equipment imported for the Project;
- ▶ facilitate work permits, visas and other personnel-related matters;
- ▶ where appropriate/required, assist with any necessary resettlement of people from the Project site;
- ▶ ensure the continued existence of the Offtaker (or of a credit-worthy successor entity);
- ▶ permit the Generator to (a) open and maintain bank accounts, (b) freely convert currency at a market rate of exchange, and (c) transfer foreign exchange into and out of the host country; and
- ▶ subject to various caveats and carve-outs, compensate the Generator for any increased costs and/or decreased revenue resulting from any changes in law and/or Political Force Majeure Events.

It is also common in the Implementation Agreement (or its equivalent) for the host Government to:

- explicitly agree to enter into a direct agreement with the Generator's lenders; and
- grant tax and/or import/export duty exemptions, to the extent that any are offered in addition to any available at law).

⁴⁴ A notable exception is Rwanda where the early termination buyout provisions are in the PPA; however, in this case all successfully project financed transactions have benefited from a full Government guarantee of the Offtaker's obligations under the PPA.

The Implementation Agreement (or its equivalent) will also often impose obligations on the Generator in favour of the host Government. These may duplicate in whole or in part the obligations already owed to the Offtaker under the PPA; however, the effect is to permit the host Government to directly enforce the relevant obligations, including:

- ⦿ the principal obligation to carry out the project activities in accordance with domestic law, any applicable Permits and prudent utility practice, etc.;
- ⦿ requirements as to local content and the employment and training of local staff; and
- ⦿ informing the host Government of any issues and/or delays in the issue or renewal of Permits.

7.8.2. Project structure with AGC

It is anticipated that Governments will play the following roles within the AGC structure for the following reasons:

Members / shareholders / equity investors in AGC	<p>In order to achieve a high level of political buy-in and regional cooperation, we believe it is important for the AGC intermediary to be at least partially African-owned. One of the major hurdles to large cross-border transactions is a lack of coordination between states and AGC can act as a catalyst to bring countries together to achieve common objectives. It is however important to note that AGC's day-to-day operations will be independently managed to avoid political interference and undue influence, as further detailed in <i>Section 8 (Corporate Structure, Governance and Risk Management)</i>.</p> <p>From a financial perspective, direct equity investment will give the Governments added incentive to ensure the success of AGC, as well as providing capital which could be used to defray losses incurred by AGC as a result of default by state owned entities. Such equity investment may be funded through concessional sources, such as the World Bank's International Development Association (IDA) allocations, as was the case with Africa Trade Insurance Agency. Given AGC's regional remit, countries may also be able to tap into regional IDA allocations to supplement their national envelopes. Please refer to <i>Section 5.11 (Equity)</i> above for further details.</p>
Counterparties to Implementation / Government Support Agreements	<p>As set out above, it is not envisaged that Governments would be required to provide guarantees in respect of the power purchase obligations of the Offtakers, as is common under existing bilateral arrangements. However, certain risks such as political force majeure, expropriation of a power Plant and adverse changes in law are not risks that AGC can mitigate and some are within the control of the host Government. As such, it is anticipated that AGC (or the IPPs directly) will continue to require the host Government to agree (where relevant) not to take such action and to compensate AGC (or the Generators directly) for losses arising if such events arise.</p>
Legislators	<p>In some countries, regulatory and/or legislative changes may be required to enable AGC to operate within their territory but these are consistent with the parallel work being undertaken by RERA to harmonise regional regulations to facilitate cross border trade.</p>

7.9. Flow Through Approach v Direct Approach

As set out in *Section 8.1.4 (Recommendation)* of the Corporate Structure, Governance and Risk Management section below, it is envisaged that AGC will initially be incorporated under the national laws of an African state but that ultimately:

- ⦿ AGC may be established under international treaty ("Establishment Treaty"), in a similar way to AFC, ATI, ARC and many other existing organisations with sovereign states as members;
- ⦿ AGC may also enter into bilateral participation agreements ("Participation Agreements") with each sovereign Member, in a similar way to which each member country of ATI enters into a program agreement with ATI.

Whether pursuant to a shareholding in a corporate structure or through an Establishment Treaty and Participation Agreement, the Host Government will already have a contractual relationship with AGC prior to AGC entering into a PSA with an Offtaker in that jurisdiction. To the extent the Government obligations included in an Implementation Agreement (as listed above) are generic, it may be desirable for such obligations to be included in the constitutional documents and/or shareholder agreement of AGC, or its Establishment Treaty and/or Participation Agreements (as applicable), such that the host Governments, upon becoming Members of AGC, agree such matters for the benefit of all of the Plants to be constructed within their country through the AGC structure. AGC would then pass on the benefit of such undertakings to the Generator under the PPA. This would have the advantage of creating a level playing field for all Projects in all Member countries and greatly simplifying and reducing deal-specific negotiations. In this case, the obligations of the relevant host Government would be owed to AGC, who would in turn enter into a back-to-back obligations with Generators in order to confer equivalent rights on them (the "**Flow Through Approach**").

However, AGC cannot be caught in the middle in respect of issues over which it has no control and no ability to mitigate (such as political force majeure or adverse change in law) and will therefore only be able to act as a conduit in respect of many of these rights and obligations. At least initially therefore, Generators (and their lenders) and the Governments may prefer to have a direct contractual relationship with each other rather than relying upon AGC to enforce their respective rights. We have therefore assumed that there will still be an Implementation Agreement between the Generator and the Generator's host Government to provide them with direct contractual rights and obligations between each other (the "**Direct Approach**"). The preferred approach will be explored during stakeholder consultation during the implementation phase.

7.10. Credit Support Arrangements and AGC's Credit Mitigation Strategies

As discussed above, it is currently common in sub-Saharan African countries for payment default by an Offtaker to lead to the host Government becoming liable to purchase the Plant under an early termination buyout regime. To the extent the payment obligations of the Offtaker and/or Government are covered by a partial risk guarantee, the Government is also often required to provide a sovereign counter-indemnity in favour of the issuer of the partial risk guarantee. By virtue of its ownership structure and ability to identify an alternative purchaser in case of default, AGC is able to mitigate a number of these risks in a manner that a Generator would be unable to achieve on a bilateral basis.

It is vital that AGC has sufficient credit mitigation structures and strategies to ensure that it is not over-exposed to default by any single Offtaker. Without such rights, AGC may not be able to maintain the credit strength necessary to fulfil its role as a creditworthy counterpart for the IPPs. In addition to the contractual rights listed in the table above and summarized below, the corporate structure of AGC, in which Governments, Donors, DFIs and MDBs sit as co-shareholders provides softer comfort against the risk of Offtaker default given the negative impact this may have on the relationship between the defaulting Offtaker (and its Government) and the Donors, DFIs and MDBs who may be supporting the relevant Government in other ways outside the scope of AGC.

As noted in *Section 7.2 (Project finance basics)* above, the Generator's two key credit exposures are:

- ① the Offtaker's promise to pay for electrical energy which has been delivered or otherwise made available in accordance with the provisions of the PPA ("Liquidity Risk"); and
- ② the Offtaker and/or host Government's promise to pay compensation and/or purchase the project assets (if required to do so by the Generator) upon early termination of the project due to the occurrence of one or more risk events which are either the fault or otherwise the responsibility of the Offtaker and/or host Government ("Termination Payment Risk").

7.10.1. Liquidity Risk

The majority of IPPs utilise project finance structures, such that the only source of cash available for debt service is the payments under the PPA. Accordingly, the Offtaker is generally required to post a letter of credit, to fund an escrow account or provide a similar means of liquidity support (each a "Liquidity Support Instrument"), which can be drawn on by the Generator in case of delayed payment by the Offtaker to enable the Generator to meet its debt service and other payment obligations.

Under the AGC structure, the Generator will be taking credit risk on AGC, which will in turn be taking credit risk on the Offtaker. AGC will be sufficiently well-capitalized to be able to continue making payments under the PPA

even if there is delay in payment under the PSA. It is therefore less dependent on liquidity support from the Offtaker, but still has an interest in mitigating its credit exposure to the Offtaker and incentivizing it to pay on time. Through our discussions with market participants, the majority view seems to support still requiring Liquidity Support Instruments from the Offtakers in order to both reduce AGC's credit exposure and act as an early warning trigger in case of payment delay, prior to reaching a payment default under the PSA. This however remains open for further discussion with AGC's investors and the Offtakers and it is likely that a compromise position will be reached such that if liquidity support is still requested, it will be at a lower quantum than currently required, and result in a lower fiscal impact on the Offtaker.

7.10.2. Termination Payment Risk

Termination of the PPA as a result of Offtaker and/or Government default or Force Majeure generally gives rise to an obligation on the Offtaker and/or Government to purchase the Plant. The quantum varies depending on the reason for termination (please refer to row 19 of the risk allocation table in *Section 7.6 (Allocation of key risks in AGC's PPAs and PSAs)* and the more detailed risk allocation table in *Annex 1 (Detailed Allocation of Key Risks in PPAs and PSAs)* for further details).

If an Offtaker defaults, AGC will seek to preserve the PPA by securing an alternative Offtaker for the surplus power. In such event, it is equitable that the defaulting Offtaker should be liable for a termination payment, but such payment does not need to cover the outstanding debt (and equity) and termination costs, assuming the nature of the Offtaker's default does not adversely affect the ability of the Plant to continue operating. Instead it needs to provide a buffer for AGC to enable it find an alternative purchaser for the relevant power. We would propose (for discussion) that the compensation would be equal to 2 years of forecast revenues in respect of power contracted to be purchased under the terminated PSA. The termination payment liability of an Offtaker under the AGC structure will therefore often be significantly less than under a direct bilateral PPA with the Generator. While it identifies and negotiates with an alternative Offtaker, AGC will sell any surplus power in the market at the best price it can secure, so 2 years' of revenues should provide AGC with revenue protection (which it will use to pay the Generator for the surplus power) for a longer period than 2 years. Depending on the market pricing, AGC may also opt not to enter into a replacement long term PSA and may continue to sell the surplus power on the market.

“ Through its structure, AGC significantly reduces the risk of a PPA being terminated. Under current bilateral PPAs (that may have taken years to agree), the Generator and its financiers will not take the risk of being able to secure an alternative Offtaker if the incumbent Offtaker defaults. However, AGC, as an intermediary with standardized PSAs with multiple Offtakers, is much better placed to find an alternative purchaser for the power originally destined for the defaulting Offtaker. If an Offtaker defaults under a PSA, AGC will call on any liquidity support provided to it and use its capital base to continue paying the Generator and prevent or cure a corresponding default arising under the PPA while it seeks an alternative Offtaker. **”**

“ Our initial discussions with the IMF indicate that as the likelihood of a termination payment liability arising (and therefore the counter-indemnity being triggered) is dramatically reduced as a result of the mitigation strategies employed by AGC, such contingent liability of the Government may be given a lower risk weighting in their indebtedness calculations than would otherwise be the case. We are continuing our discussions with the IMF in this regard. **”**

Given the constrained balance sheet of most Offtakers, and the fact that in such circumstances they are already in default, it is highly unlikely that they would have sufficient reserves to be able to pay any such termination payment. The Government should therefore be required to provide support in respect of such termination payment, but as noted above, the quantum of this will generally be substantially less than the quantum of a termination payment arising on Offtaker default in a standard bilateral PPA.

There will however still be circumstances in which the whole of the PPA terminates. For example, due to an act of the host Government, such as expropriation or change in law, preventing the Generator from operating the Plant. In such event, regardless of how many Offtakers there are for the Project, the defaulting host Government will be liable for the full quantum of the termination payment (covering outstanding debt, outstanding equity and a return on equity) as neither the Generator nor AGC would be able to recoup its losses by continuing to operate

the Plant. Such risks (and therefore the associated contingent liability) are within the control of the Government and as such should be acceptable to it. This obligation will be set out in the Implementation Agreement (under the Direct Approach) or the Establishment Treaty/Participation Agreement under the Flow Through Approach.

Under the Flow Through Approach, the Generator's recourse is against AGC. As discussed in [Section 5.8 \(Capital Requirement\)](#) above, AGC's capitalization model assumes that it will be adequately capitalized in order to be able to pay any early termination payment arising under any PPA it enters into. Therefore if AGC were to bear the Termination Payment Risk, the Generator and its lenders could rely on AGC and would not need to seek a third party guarantee / insurance. This approach should be much more attractive to the Generator and its lenders, as they would be likely to receive any applicable termination payment much quicker from AGC than from the Government.

That would however leave AGC with the risk of recovering in full from the Government. AGC would also need to decide whether to exercise any associated call option pending any decision by the Government as to whether it wishes to exercise its corresponding call option under the Government support arrangements (if the Generator has not already exercised a put option to force AGC to purchase the Plant). This could lead to AGC owning (and operating) a Plant, which it is not set up to do, but the analysis of this is similar to a lender's right to step into a PPA in case of default by the Generator – the lender is equally not staffed to run a Plant but will keep on or bring in appropriate manpower if necessary while it finds a buyer for the Plant.

We have considered whether the Generator and its lenders may be willing to accept a lower termination payment in return for such payment being made much quicker. It would however seem unlikely that the lenders would allow the shareholders to receive any payment in circumstances in which the debt was not fully repaid. As such, any reduction in the termination payment is likely to fall on the shoulders of the shareholders of the Generator and it would not be equitable for the shareholders to not be adequately compensated in case of Government or Offtaker default or prolonged Local Political Force Majeure.

Where AGC incurs a termination payment liability due to the default of one of its Members (or such Member's national utility), the Establishment Treaty and/or Participation Agreement may provide for a counter-indemnity from the host Government in favour of AGC (in a similar fashion to the counter-indemnity contained in each of ATI's program agreements with ATI member countries). Consideration should however be given to the impact this would have on the sovereign balance sheet and indebtedness levels.

In order to mitigate the risk of its capital being depleted as a result of paying large termination payments, AGC will seek to secure political risk insurance or guarantees for its own benefit, at portfolio level, to pass off some of this risk. Due to the diversification of the termination risk at AGC level, it should be more efficient to secure such cover at portfolio level than at individual project level. This is explored further in [Section 5.10.6 \(Sources of Leverage\)](#) above.

7.11. Other Benefits of AGC

To an extent and in a manner which is not possible under bilateral (i.e., single Generator, single Offtaker) IPP structures currently used in sub-Saharan Africa, significant benefits of the AGC structure include the ability of AGC to:

Mitigate risk	► Under current IPP structures, a grid constraint will trigger deemed energy provisions in a renewable energy PPA. Under the AGC approach, AGC will seek and utilise opportunities to continue to dispatch constrained energy and to supply it to alternative Offtakers who are not affected by the relevant constraint. Similarly, if a Plant incurs planned or unplanned downtime, AGC will seek and utilise opportunities to replace the lost power generation capacity with unused available capacity of other Generators (which may or may not be in the same country as the Plant which is subject to downtime).
Match unserved demand with surplus supply	► Similarly to the above, AGC will provide to all of its Generator and Offtaker counterparties a reasonable efforts 'match making' or 'market making' obligation; pursuant to which AGC will endeavour to match surplus supply with unmet demand on a spot and/or short-term basis. This may involve a structural management of peak demand times which 'roll' across time zones and different locations, and/or one-off / ad hoc matching.

Allow for multi-offtaker PPAs	<ul style="list-style-type: none"> ▶ By entering into separate PPAs with Generators and PSAs with Offtakers, AGC will require only one PPA with a Generator (albeit with various consequential amendments) in order to supply multiple Offtakers. In this case, the Generator will not (a) be required to negotiate individual bilateral PPAs, or (b) be concerned as to the allocation of generated power as between Offtakers. The existence of AGC in the structure will also (i) mitigate the risk of one but not all Offtakers failing to perform its PSA obligations, and (ii) cater for such a scenario in a structured manner; and
Match offtakers with their most efficient source of power supply	<ul style="list-style-type: none"> ▶ It is envisaged that AGC will (a) contract with multiple Generators and Offtakers throughout a number of neighbouring, interconnected countries; and (b) have wheeling agreements with TSOs in each AGC member country. Accordingly, it is expected that AGC will be able to efficiently match generation capacity with load; i.e., in terms of physical energy flows, an Offtaker's load will not necessarily be served by the Generator with whom AGC has a back-to-back PPA.
Give greater visibility regarding available capacity	<ul style="list-style-type: none"> ▶ AGC intends to publish information regarding its contracted volumes and the actual generation levels at its plants, such that the market can see when and where excess supply may arise.

7.12. Procurement Considerations

AGC will need to establish clear and transparent rules for selecting the projects it supports, whether or not it runs the procurement process itself. Procurement can be a very political issue and will need to be discussed and agreed with AGC's members and the relevant national and regional regulators.. It is likely to be an area that develops organically to reflect market dynamics and the needs of different offtakers. The benefits of a standardised, independently run process are however widely recognised in terms of ensuring a level playing field and attracting international investors.

One should not underestimate the impact the tender process can have on the success or failure of an IPP program. An effective tender requires defining the procurement methodology and process (including transparent evaluation criteria), preparing tender documents, and applying these consistently and fairly. Information should be distributed to all potential bidders evenly and the schedule, structure, and integrity of the overall procurement process must be maintained.

This section briefly explores AGC's potential role with regard to procurement and the principal goals it would seek to achieve in doing so. A more detailed discussion is included in *Annex 8 (Procurement)*.

7.12.1. AGC's role in procurement

The first issue to determine is at what stage of the procurement process will AGC be involved. At one end of the spectrum, AGC could leave it to each national utility to run its own procurement processes and only get involved once the projects have been selected. At the other end of the spectrum, AGC could run the procurement processes itself.

As an intermediary, AGC will take risk on both the offtaker and the generator. Before entering into a PPA with an IPP, AGC will need to satisfy itself that the demand forecasts on which the new capacity additions are based are reasonable such that the offtaker is not likely to over-stretch itself and not be able to pay for the volume of power contracted. On the generator side, AGC will need to ensure that it is comfortable to act as offtaker for the projects selected through the relevant procurement process - it could not accept a blanket obligation to contract with whoever wins the tender.

If AGC simply participates in tenders run by others, it would not be able to exert much influence over the structure or terms of the tender, including the form of the PPA. A standard PPA is unlikely to include the credit mitigation structures discussed above which are intrinsic to AGC's business plan and its ability to maintain its creditworthiness and take exposure on utilities without requiring sovereign guarantees. AGC will also wish to ensure that any tender process in which it participates complies with international procurement principles such as anti-money laundering (AML), combatting the financing of terrorism (CFT) and anti-corruption. It will also not wish to contract with anyone who is blacklisted by international organisations such as the World Bank or the European Union. If

AGC is to assume the offtake obligations under some existing, signed PPAs, it will not have had any influence over the way in which such projects were originally procured. It will however have to satisfy itself that such projects were awarded in a fair and transparent manner.

7.12.2. Regional factors

AGC will work closely with Offtakers, regulators and power pools to align its procurement activities with their processes and priorities, ensure consistency and advance common goals. Given its regional outreach, AGC would be able to deliver a wide range of benefits to both Offtakers and potential project developers. It could take a regional approach to optimise the most efficient use of renewable energy sources within a region, for example by facilitating multi-generator / multi-offtaker solutions for projects so as to make full use of solar energy sources during peak generation hours and despatchable sources such as hydro when irradiation levels are low. This should reduce the cost and improve the availability of energy as all resources would be used to their full potential.

As AGC will be operating on a regional basis, it will be important to establish which procurement rules it would be subject to. Particularly in the case of IPPs with multiple offtakers from different countries, it may not be feasible for AGC to comply with the procurement rules of each country involved. There may also be restrictions on a country delegating its procurement authority to a separate entity such as AGC. This will need to be confirmed in each case, but could potentially be resolved through the Establishment Agreement of AGC, if each Member agreed that AGC's procurement rules (which it would be involved in determining) would take precedence over its domestic rules and its domestic rules would not apply to AGC. A further complexity may be introduced by virtue of AGC's capital providers. Where donors, MDBs and/or DFIs are providing capital to AGC, they may wish to impose their own procurement rules. This could lead to conflicts between e.g. national rules and donor rules or between e.g. the rules of one donor and another donor. However, most MDB procurement guidelines allow for usage of another MDB's procurement regime if it offers the same extent of transparency and fairness.

Through its independence and standardisation, AGC could become a regional procurement facilitator and level the playing field of differential standards and procedures applying in different jurisdictions. Through an integrated regional approach to procurement, based on agreed capacity targets and technology types, AGC as a single point procurement authority could provide new certainty to the market by using standardised documentation within a structured procurement programme.

8 Corporate Structure, Governance and Risk Management

In order for AGC to operate successfully and fulfil its ambition to catalyse private sector investment and broader power market development, broad-based political ownership of the concept is required. AGC also needs to be able to operate efficiently in its interactions with the market. It must have legal personality and be able to enter into contracts, hold assets, employ staff and be held accountable for its actions. It requires the skills and experience to implement the business plan including negotiating and administering PPAs, PSAs and related transaction documents, managing payment processes, investor relations, dealing with practical and technical issues and all other aspects of operating a power purchaser and trader.

AGC will require institutional structure with legal capacities and governance mechanisms that will permit the participation of State and non-State actors, including African countries, donors, multilateral development banks, private sector investors and other stakeholders that could play a role in helping achieve the AGC's development objectives.

To serve African State governments by acting as a regional creditworthy offtaker and power trader, AGC must function across the public-private spheres which implicates both international law raised by multi-state interactions (and interactions with MDBs and other multilateral bodies) and the various national laws applicable to non-State actors.

This section provides an overview of the key considerations in determining the most appropriate legal and governance structure for AGC. Please refer to *Annex 4 (Africa GreenCo Corporate Structure, Regulatory & Governance Options)* for a more detailed analysis.

8.1. Corporate Structure

8.1.1. Parallels with existing organisations

In exploring the legal structuring options available to AGC, we have closely considered the structures adopted by other African organisations established to serve development objectives, which combine public and private sector participants and/or functions. For example:

AFC	combines public sector members with mainly private sector shareholders in a single legal treaty-based entity and operates commercially;
ATI	a single legal treaty-based entity with majority public sector membership but a board of directors comprising appointees of different classes of shareholder, some of which are required to be from the private sector;
ARC	a treaty-based organisation comprising two distinct legal entities, an international organization to facilitate multi-state discourse and planning and the other a commercial operating company established and regulated for sound insurance operations under the laws of Bermuda; and
AGF	AGF – a company incorporated in Mauritius, currently owned by Danida, AECID and the AfDB but planning to bring in other DFIs.

“ AGC should be an African-owned and African-led but independently managed organisation whose strategy and priorities are set by the member countries in discussion with the other investors and with advice from relevant experts. ”

“ It needs to make quick, commercially sound decisions without becoming bogged down in politically-motivated issues while being sensitive to political process and the need to build capacity and buy-in from stakeholders. ”

8.1.2. Primary corporate structuring considerations

There are two broad classes of “corporate entities”: those established under national laws and those formed by treaty and operating under international law. Please refer to [Annex 4 \(Africa GreenCo Corporate Structure, Regulatory & Governance Options\)](#) for a summary of the key differences between them and the impact this may have on AGC operationally.

AGC has garnered significant momentum and interest in the international development community. That momentum may require quick action to pilot the AGC concept, which may languish if the preferred institutional model requires a lengthy treaty negotiation and signing processes. See the timelines and pros/cons in the table in [Annex 4 \(Africa GreenCo Corporate Structure, Regulatory & Governance Options\)](#), where treaty negotiation may take 18-24 months based on experiences in other African development institution contexts. Political will and endorsement by African institutions like the AfDB, AU and relevant regional entities (e.g. SADC, SAPP, RERA etc. in the Southern African context) may speed this process, which can be an important way to obtain broad buy-in and political engagement which may increase the potential for success and institutional longevity.

The overall timeline until a treaty-based entity can be operational will also depend on the number of States required to bring the entity into existence. As set out above, AGC’s business will need to be piloted in a small number of countries initially in order to prove the model before being rolled out within the region and across the continent. Taking the example of SADC/SAPP, it would not be necessary for all 12 member States to sign the treaty in order for it to come into force. The conditions for coming into force are to be agreed by the member States concerned. It could for example come into force upon signature by 2 of the 12 member States, with the option for other States (whether SADC members or other States once AGC expands beyond SADC) to subsequently sign (and ratify) the treaty in order to become members of AGC. If this approach is taken, care should be taken to ensure that the initial treaty is structured in a way which would be acceptable to future members.

Establishing a national entity is much more straightforward as you are operating within the pre-designed structures of national rules and regulations. It would still take time to negotiate any exemptions from general tax treatment, restrictions on foreign ownership, repatriation of profits etc., but would only involve dealing with one national administration.

8.1.4. Recommendation

The ultimate corporate structure will depend on the preferences of AGC’s founder members and may evolve over time. For practical reasons, the initial implementation vehicle will be a nationally incorporated entity, but the transaction documentation will, to the extent possible, be structured in a way to permit a transfer to a subsequent international organisation.

8.2. Governance

A key strength of AGC is that it is designed to accomplish the objectives of a “Public Private Partnership,” combining high-level political support and ownership with the efficiencies of a commercially run business. In order to fulfil its intended role in the market, AGC needs to balance the political interests of its members with the needs of its private sector counterparties. It must operate as an independently managed commercial entity and be recognized by its counterparties as such.

There are several examples of African institutions, which have achieved a separation of political roles and operational responsibilities through a combination of their legal and governance structures. These include AFC, ATI and ARC. Please refer to [Annex 4 \(Africa GreenCo Corporate Structure, Regulatory & Governance Options\)](#) for further details.

8.2.1. Credit rating considerations

Given AGC’s ambitions to serve as a creditworthy offtaker, and achieve a minimum rating equivalent to A (Standard & Poor’s (S&P)/Fitch) or A2 (Moody’s), it is important to understand how the legal structure, ownership and governance of AGC may impact upon the rating it can achieve. Management and governance issues are also carefully considered by ratings agencies when assessing an enterprise’s creditworthiness. The term “management and governance” encompasses the broad range of oversight and direction conducted by an enterprise’s owners, board representatives, executives, and functional managers. Their strategic competence, operational effectiveness, and ability to manage risks shape an enterprise’s competitiveness in the marketplace and credit profile. If an enterprise has the ability to manage important strategic and operating risks, then its management plays a positive

role in determining its operational success. Alternatively, weak management with a flawed operating strategy or an inability to execute its business plan effectively is likely to substantially weaken an enterprise's credit profile. It is therefore vital that AGC has a strong and transparent management and governance structure in which well-governed and well-respected shareholders such as existing multilateral DFIs (e.g., AfDB) play a significant role.

The methodologies for assessing the creditworthiness of national entities and international entities differs and is summarised below.

National corporate entity

Standard rating methodologies are relatively straightforward when assessing a national corporate entity. Taking the example of S&P, their methodology comprises two elements: overall business risk and overall financial risk, with the following sub-categories:

Overall Business Risk	Overall Financial Risk
Country Risk	Accounting
Industry Characteristics	Governance / Risk / Financial Policy Score
Company Position	Cash Flow Adequacy Score
Profitability / Peer Comparison	Capital Structure / Asset Protection Score Liquidity / Short Term Factors Score

In analysing management and governance, S&P review management (including strategic positioning, risk management/financial management and organizational effectiveness) and governance. Subfactors used to evaluate these include strategic planning processes, consistency of strategy with organizational capabilities and marketplace conditions, ability to track, adjust, and control execution of strategy, comprehensiveness of enterprise-wide risk management standards and tolerances, management's operational effectiveness, management's expertise and experience, management's depth and breadth, board effectiveness, entrepreneurial or controlling ownership, management culture, internal controls and financial reporting and transparency.

International entity

When assessing an international / multilateral entity, the ratings methodologies look further beyond the entity itself and consider the attributes of the core shareholders. By way of example, under the DBRS methodology⁴⁵, credit rating for international/multilateral entities turns on two broad but interrelated assessments. Firstly, a support assessment which, evaluates creditworthiness of the "core group of shareholders" considering the level of financial commitments to the institution, both individually (member or shareholder) and collectively.

The second area of assessment (intrinsic) evaluates the institution's "stand-alone financial strength" including reputation, capital base, right to call on additional capital, credit risk and liquidity requirements. Both assessments are interrelated and combined to provide a rating based on the credit strength of the institution. Not uncommonly, both assessments arrive at a similar conclusion and thus rating.

Support Assessment ⁴⁶	Intrinsic Assessment Factors
Combined Rating of Core Shareholders	Franchise Strength ⁴⁷
Credibility of Support Commitments	Earnings Power
Impact of Dominant or Controlling Shareholders	Risk Profile
Multiple Sources of Support	Funding and Liquidity Capital Adequacy

⁴⁵ See: DBRS Ratings Methodology: <http://www.dbrs.com/research/266486/rating-supranational-institutions-archived.pdf>.

⁴⁶ The "support assessments primarily reflect the creditworthiness of the "largest and most committed shareholders in the institution. A combined credit rating of core shareholders, usually close to the weighted median rating of the group, is used as the starting point to judge their individual and collective capacity to support the institution. However, the support assessment also reflects the specific shareholder structure of the institution and the credibility of their individual and collective support commitments." Under this process, a finance institution would enjoy a stronger rating if, for example, it had AAA-rated or AA-rated as shareholders or enjoys "multiple credible sources of support".

⁴⁷ For a new institution like AGC, franchise strength will be lower, given a lack of operating history.

The “support assessment” normally plays the “dominant role” in establishing the final rating since financial commitment of the core group of investors may overcome concerns about institutional intrinsic strength. Alternately, “intrinsic assessment” strength will generally only marginally improve a rating determination given the importance of financial strength in market-facing transactions. To the extent AGC’s major shareholders are sovereigns or other multilaterals with good individual/underlying credit strength, AGC may benefit from a halo effect from such shareholders to the extent of legally binding financial commitments from such shareholders to AGC.

However, to the extent AGC’s shareholders are sovereigns with poor individual/underlying credit strength, this could potentially have a negative impact on AGC’s overall credit rating. This emphasises the importance of having creditworthy, well-governed and well-respected Shareholders (such as AfDB, KfW, DFID, IFC, EIB) within AGC’s corporate structure. To mitigate risks associated with less creditworthy sovereign members, it is AGC’s intention that all equity to be contributed by African sovereigns will be fully paid in and as such AGC will not be relying on their credit strength and ability to secure funds at a later date.

It is also worth noting that DBRS may include private or other institutional shareholders within the core group of some multilaterals, as long as support commitments are viewed as sufficiently credible. In addition, if a multilateral has a fully- or partly-owned subsidiary, DBRS will usually rate the subsidiary as a multilateral under this methodology, even if it has only one direct owner. DBRS would likely treat the parent multilateral as the core shareholder for purposes of evaluating the quality of support commitments and the existence of a dominant or controlling shareholder.

8.2.2. Proposed membership and governance structures for AGC

Based on our analysis of the governance structures employed by existing organisations and the political and commercial drivers of AGC, we propose that the AGC TopCo and the AGC OpCo should have the membership and governance structures set out below. Where there are multiple entities, it is important to clearly delineate the respective roles and responsibilities of each entity. The key is to ensure that AGC’s governance rules are designed in a manner that preserves independence and professionalism, and minimizes the risk of conflict of interest that may arise in cooperative ventures some of whose capital is contributed by States that wish to enjoy development benefits. Good governance also feeds into credit rating assessments and it may be advisable for AGC to voluntarily adopt a recognised code of governance, such as King III.

The broad roles and responsibilities of each entity will be clearly set out in the shareholders agreement or Establishment Treaty and are open to discussion and agreement between the founding Members but some initial thoughts on this are set out in *Annex 4 (Africa GreenCo Corporate Structure, Regulatory & Governance Options)*. The principles embedded in the Establishment Treaty will be supplemented by a governance manual that makes clear the composition and respective responsibilities of the Board and its Sub-Committees, the matters reserved for the Board etc.

If, for practical purposes, the initial AGC entity is established under national law, similar governance structures and voting/director appointment rules could be adopted within the national entity and this would smooth the transition to the ultimate treaty-based international organisation.

8.2.3. Relationship with PSA counterparties

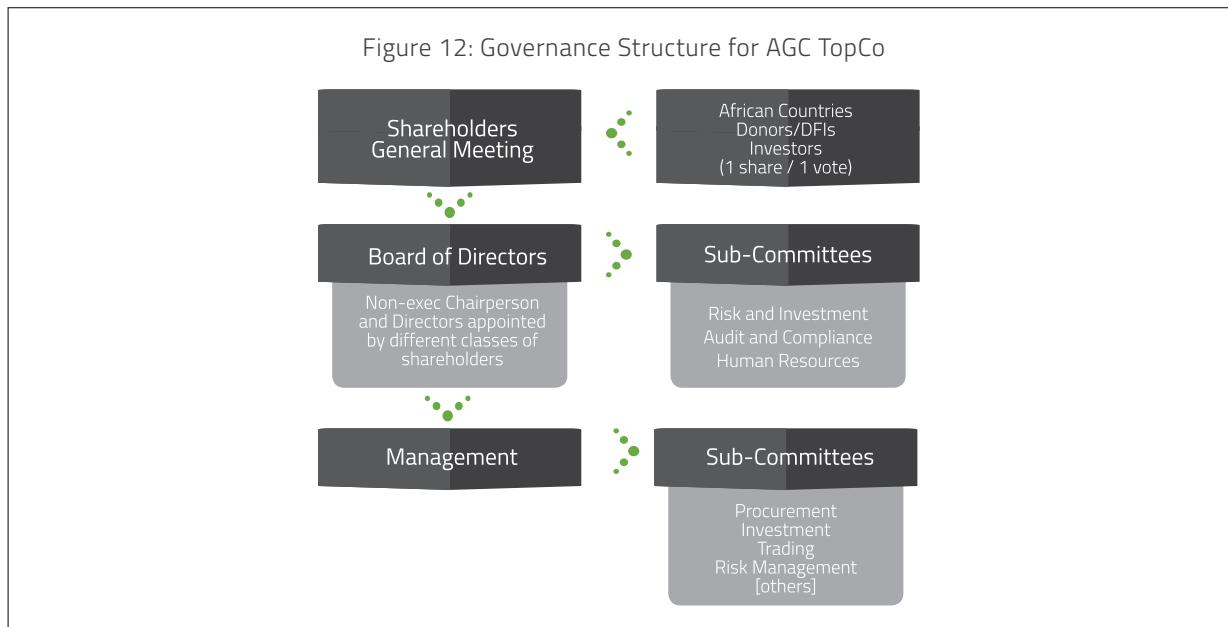
It is intended that the majority of AGC’s PSAs will be entered into with national utilities within countries who are members of AGC. As well as achieving strategic alignment, this ensures that the relevant sovereign has “skin in the game” which should encourage it to ensure that its national utilities perform their obligations under their respective PSAs. It is envisaged that in signing the shareholders agreement or Establishment Treaty, member States will agree to grant to AGC, or procure the grant to AGC of, all necessary licences and approvals to enable AGC to operate within their country. As discussed in *Section 7.8.2 (Project Structure with AGC)* above, some of the matters currently addressed through Implementation Agreements would also be addressed through AGC’s shareholders agreement or Establishment Treat to ensure consistency and reduce the need for bilateral negotiation on a project-by-project basis.

Prior to AGC entering into a PSA with a national utility, the relevant sovereign members will be required to hold an equity investment in AGC proportional to the volume of power they wish their national utilities to be able to purchase from AGC OpCo. Their national utility’s rights to offtake power from AGC will be limited to an agreed multiple of the equity invested, such that the quantum of the equity contribution required will be significantly less than the total liability under the PSAs entered into between AGC and the national utility of such Member and represent a significantly

lower burden on the national balance sheets when compared to issuing sovereign guarantees in respect of such PSA obligations. This equity will be available to AGC to remedy a default by the national utility, as set out in detail in [Section 7.8.2 \(Project Structure with AGC\)](#) above.

As a means to incentivise Member states to provide a conducive enabling environment for IPPs, to assist Generators with permitting processes and to avoid any discriminatory treatment, a mechanism could be considered whereby Members would receive additional equity for every IPP that achieves COD within its territory.

As membership of AGC is also open to private investors, it is also possible for non-sovereigns, such as private industrial Offtakers, to become Members of AGC TopCo and to enter into PSAs with AGC OpCos. In such event, the minimum equity contributions applicable to sovereign members would be equally applicable to such private investors.



Where AGC enters into PSAs with Offtakers which are not state owned national utilities of Members or Members in their own right, and AGC does not therefore benefit from the political leverage and financial collateral provided by the relevant sovereign member as set out above, such Offtaker will be required to post additional collateral in respect of its PSA obligations in order to give AGC better credit protection against its default. Please refer to the risk allocation table in [Section 7.6 \(Allocation of key risks in AGC's PPAs and PSAs\)](#) for further details. In line with prudent risk management strategies, it is also likely that AGC will limit the volume of its PSA exposure to such counterparties.

8.2.4. Relationship with existing regional institutions

AGC will work in close cooperation with the existing institutions in the region, and in particular the power pools, and is intended to supplement and not duplicate or replace the roles of these entities. The AGC entities should therefore be focussed on the business of AGC and issues such as regional planning and cooperation regarding network improvements and regulatory reform should, in the case of the SADC region, be left to SAPP or RERA, or by EAPP and RAERESA in the context of COMESA. AGC will seek membership of each of the power pools within which it operates and become a party to such discussions and initiatives in this way.

8.2.5 Voluntary Exit

So long as AGC OpCo is supplying power under a PSA with a Member or the national utility of a Member, such Member must remain a Member of the AGC TopCo. This is important in order to ensure political and financial leverage in case of issues arising under the PSA. Once all outstanding liabilities under each such PSA have been discharged, a Member may opt to leave AGC TopCo and sell its shares in AGC TopCo.

As set out in [Section 5.13 \(Financial Performance\)](#), it is envisaged that the non-dividend-bearing callable capital provided by donors would automatically convert to a full dividend-bearing class of shares upon the occurrence of agreed trigger events relating to the commercial profitability of AGC. This would enable the donors to sell their shares to incoming investors.

8.2.6 Default / Expulsion

If a Member or the national utility of a Member is in default under a PSA with AGC OpCo and the equity contribution of the Member has been exhausted to cover losses associated with such default, AGC TopCo may expel such member.

8.3. Risk management

If AGC TopCo is established under national laws, it may be subject to some regulation but this is unlikely to be the same level of stringent regulation an equivalent entity within an established regulatory environment such as Western Europe or the United States must adhere to. If AGC TopCo is established as an international organization, it will not be incorporated under the laws of any state and will instead be subject to public international law. It will not therefore be subject to regulation by any state. It is therefore vital for AGC to embed in its governance structures policies and procedures to govern its internal operations in accordance with international standards, such as Basel (for capital adequacy and liquidity), IFRS (for accounting) and international best practices (e.g., OECD Good Governance Principles for corporate governance) and adhere to comprehensive risk management protocols in all of its activities. It must run its business within clear operating guidelines including maximum exposure limits to any given counterparty, country or technology in order to achieve a diversified portfolio and avoid undue reliance on any one area.

AGC therefore intends to behave as if it were regulated by one of the major international financial centres (such as the UK, New York, Hong Kong or Singapore) and its associated regulatory bodies and emulate what is considered best practice in regulated industries in terms of its Governance, Risk Management and Control (GRC) arrangements. We set out below some of the key risk management structures and processes to be implemented, but note that this should be proportional to the size and scope of the business at any given time. The essential ingredients, however, should be in place at the outset such that the risk management framework can grow in line with the business. A Chief Risk Officer should be appointed who would be responsible for establishing and documenting a risk management framework based upon a 'three lines of defence' model that would operate across the TopCo and the OpCos to provide consistent oversight, even if they are established in different jurisdictions. The three lines of defence comprise:

- ① 1st line checking by investment and trading staff in the form of peer reviews/double sign off procedures etc.
- ② 2nd line checking of 1st line controls by independent compliance staff following a risk based compliance plan.
- ③ 3rd line control by an internal audit (IA) function that reports to the Audit and Compliance Sub-Committee and not to executive management. As noted above, the Audit and Compliance Sub-Committee should be chaired by an independent non-executive director who reports directly to the Chairperson of the Board to act as an independent check on executive management. The IA team should work to a risk based audit plan and be centralised at TopCo level to ensure measurement is consistent across the AGC group. Elements or all of IA can be outsourced to a third party (usually an audit firm).

The Chief Risk Officer would also be responsible for establishing and overseeing a comprehensive and ongoing risk assessment process across the key risk areas including:

- a. Capital – with an associated capital adequacy process in line with Basel III/CRD IV rules.
- b. Liquidity
- c. Operational, which should include
 - ▶ Systems (a critical risk for a trading house)
 - ▶ Business interruption
 - ▶ Human Resources
 - ▶ Counterparties
 - ▶ Suppliers (software vendors etc)
 - ▶ Compliance – Anti Money Laundering (AML), fraud and anti-bribery in particular.
 - ▶ Project risks

This process should form the basis for risk definitions and categorisation, risk register(s), including one for 'horizon' risks, control identities and measures, that are then used as the basis for:

- a. A risk appetite statement that is linked to the firm's strategy and is endorsed by the Board.
- b. A control regime appropriate to different risks (in a trading platform, controls can be 'hard wired' in, but there must be rigorous testing to ensure they are working properly).

- c. Key Risk Indicators to give the Board appropriate warning if a risk threshold is being approached.
- d. Business change approval protocols
- e. Scenario/stress testing

AGC will put policies and procedures in place, and conduct training programs, covering anti-money laundering provisions and measures to protect against financial support for terrorism as well as codes of conduct and other safeguards designed to prevent the occurrence of fraud, bribery and corruption. AGC will have a zero tolerance to bribery and other improper payments to public officials in compliance with various international laws such as U.S. Foreign Corrupt Practices Act, the OECD Anti-Bribery Convention and similar laws in other countries. In addition, AGC may engage a third party whistle blowing service to inform senior management of misconduct without disclosing the identity of the whistle-blower.

AGC will also assess any adverse environmental and social impacts of the projects it is engaged with.

The above policies, processes and procedures will inform a periodic risk framework effectiveness review, to provide the Board (and any relevant regulator) assurance that the risk management system is performing as it should.

9

Conclusion and Way Forward

This report summarizes the feasibility of the proposed structure for AGC. Significant progress has been made in developing a robust and compelling business plan. However, many concrete details in terms of the legal structure, governance, operating model, capitalization and financial performance require ongoing feedback from potential investors and promoters of the concept. On the basis of this feedback, AGC will be able to refine the strategy and take steps towards implementation.

9.1. Next Steps

This Feasibility Study incorporates the comments provided by many key stakeholders since the draft Feasibility Study was published in July 2016. Having received broad-based support for the continuation of our work into implementation stage, we are therefore starting work on a leaner business, operating and implementation model for the proposed vehicle.

This Feasibility Study proposes a flexible but comprehensive concept design that could be implemented and funded through a number of different channels. At this stage of development we have proposed a number of potential capitalisation strategies and legal, regulatory and governance options, but decisions regarding these will be shaped by the way AGC is ultimately adopted and implemented.

AGC has garnered significant momentum and interest in the African and international development community. That momentum may require quick action to pilot the AGC concept and it is anticipated therefore that AGC's business will need to be trialled in a small number of countries initially in order to prove the model before being rolled out across the region and continent. Political will and endorsement by African institutions like the AfDB, AU and relevant regional entities (i.e. SADC, SAPP, RERA in the Southern African context and COMESA, EAPP and RAERESA in Eastern and Southern Africa) should accelerate this process, and help obtain broad buy-in and political engagement - which is paramount for success and institutional longevity. As noted in *Section 1.1 (Alignment with international climate agenda and other African regional initiatives)* above, one potential route would be for AGC to be rolled out as an implementation tool of the AfDB's New Deal on Energy for Africa and AGC is in discussions with AfDB in this regard.

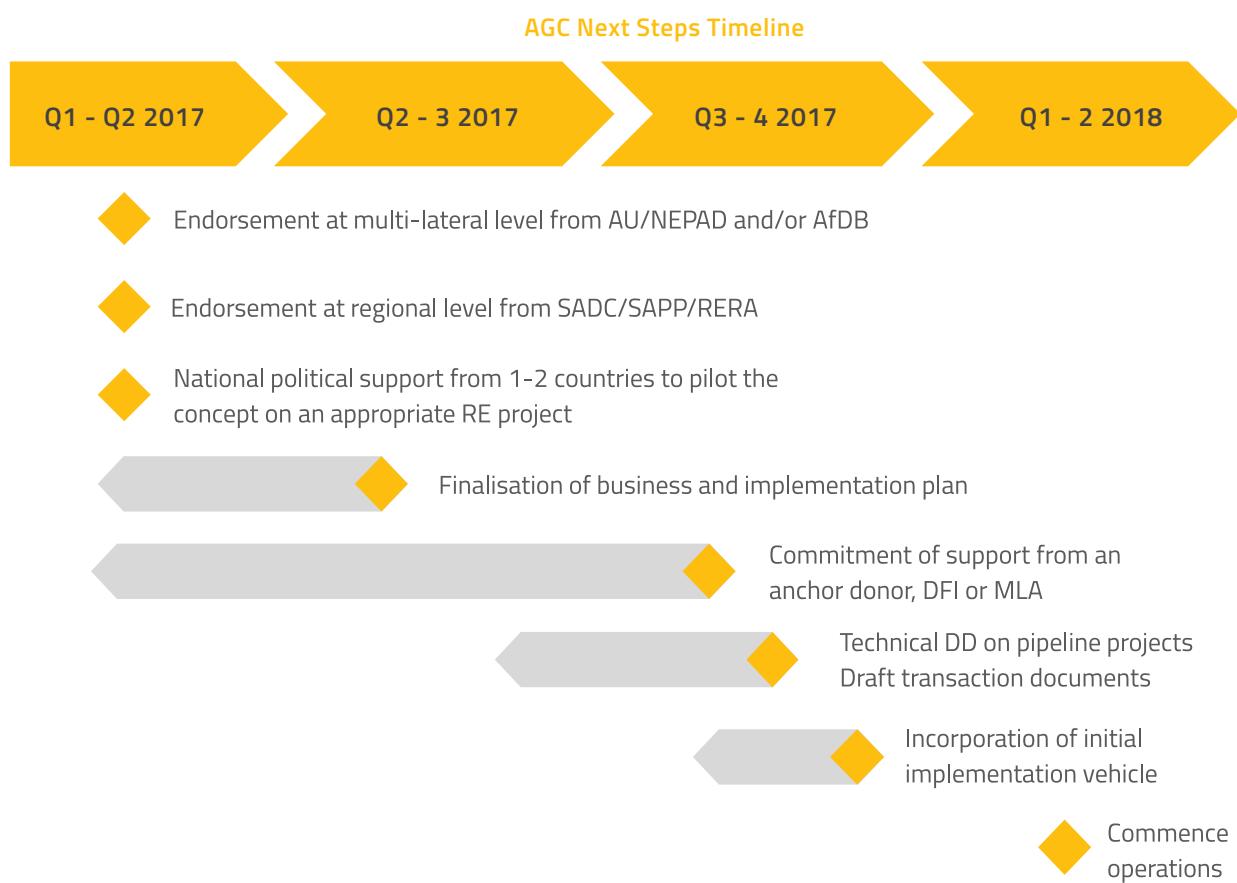
The AGC team is actively engaged in seeking opportunities to present the concept to key stakeholders and has spoken at a number of events in the last few months since the draft feasibility study was published, including the East African Power Industry Convention, the RERA Annual Conference, Bloomberg New Energy Finance summit, PIDA Week and COP22. The team will continue to raise awareness of Africa GreenCo at relevant industry events and hopes to speak at AFC Live, the Regional Energy Co-operation Summit and the SAPP Annual Meetings in early 2017, as well as continuing detailed bilateral discussions with utilities, regulators, Governments, potential anchor investors and developers.

We are confident that AGC will help stimulate the huge number of projects required to achieve the ambitious electrification goals of the continent and will continue our discussions with potential generators and Offtakers with a view to developing a more concrete pipeline. In parallel we will explore opportunities to step into existing PPAs in order to improve the credit profile of the project, facilitate refinancing and relieve some of the contingent liabilities of the existing offtakers.

9.2. Potential implementation roadmap and timeline

AGC could be launched in the near-term, especially if an approach involving a limited number of pilot countries is launched first in advance of broader regional efforts. The gantt chart below describes the possible timeline for implementing this targeted approach and focuses on three main phases:

1	Consolidating and confirming support for the AGC concept from key stakeholders in the region, at the pan-African level, the regional level and with specific host countries;
2	Identifying anchor investor(s) and iterating and refining the implementation plan with them; and
3	Raising third party capital and incorporating the legal entities and regulatory status required to begin operations.



GLOSSARY

ACEC	Africa Clean Energy Corridor	ERB	Electricity Regulatory Board
APV	Africa Power Vision	ERC	Energy Regulatory Commission
AGC	Africa Green Regional Energy: Efficient, New and Creditworthy Offtaker	ERR	economic rate of return
AFD	Agence Française de Développement	ESAP	environmental and social action plan
AfDB	African Development Bank	ESIA	environmental and social impact assessment
AICD	Africa Infrastructure Country Diagnostic	FIRR	financial internal rate of return
ATI	African Trade Insurance Agency	FiT	feed-in tariff
BNEF	Bloomberg New Energy Finance	FMO	Netherlands Development Finance Company
BPC	Botswana Power Corporation	FY	fiscal year
CAPEX	capital expenditure	GDP	gross domestic product
CDC	Commonwealth Development Corporation (UK DFI)	Generator	generator of renewable energy under a PPA with AGC
CDM	Clean Development Mechanism	GETFiT	global energy transfer feed-in tariff
CEC	Copperbelt Energy Cooperation	GSA	government support agreement
CEO	Chief Executive Officer	GSS	Grid Stability System
CERs	Certified Emission Reductions	GW	gigawatt
COD	Commercial Operation Date	GWh	gigawatt-hour
COMESA	Common Market for Eastern and Southern Africa	HFO	heavy fuel oil
CTSP	Concentrated Solar Thermal Power	HPP	hydropower plant
DAM	the Day Ahead Market	IA	implementation agreement
DFI	Development Finance Institutions	IBRD	International Bank for Reconstruction and Development
DAC	Development Assistance Committee (of the OECD)	ICSID	International Centre for Settlement of Investment Disputes
DBSA	Development Bank of Southern Africa	IDA	International Development Association (of the World Bank Group)
DEG	German Investment and Development Corporation	IDM	Intra-Day Market
DFI	development finance institution	IDC	Industrial Development Corporation
DfID	the U.K. Department for International Development	IEA	International Energy Agency
DoE	Department of Energy	IFC	International Finance Corporation (of the World Bank Group)
DSCR	Debt Service Coverage Ratio	IFU	Danish Investment Fund for Developing Countries
EAIF	Emerging Africa Infrastructure Fund	IMF	International Monetary Fund
EAPP	East African Power Pool	IPP	Independent Power Producer
EDM	Electricidade de Mozambique	IRENA	International Renewable Energy Agency
EMBI	Emerging Market Bond Index	KfW	Kreditanstalt für Wiederaufbau (German development bank)
EIB	European Investment Bank	kW	kilowatt

GLOSSARY

kWh	kilowatt-hour	PV	Photovoltaic
LC	letter of credit	RAERESA	Regional Association of Energy Regulators for Eastern and Southern Africa
LCOE	levelized cost of energy	RE	Renewable Energy
LCPDP	Least Cost Power Development Plan	RERA	Regional Electricity Regulators Association of Southern Africa
LHPC	Lunsemfwa Hydro Power Company	RfP	request for proposals
McKinsey	McKinsey & Company	RfQ	request for qualification
MCP	Market Clearing Price	ROE	return on equity
MDB	multilateral development bank	SADC	Southern African Development Community
MFI	multilateral finance institution	SAPP	Southern African Power Pool
MIGA	Multilateral Investment Guarantee Agency (of the World Bank Group)	S&P	Standard & Poor's
MoU	memorandum of understanding	SBLC	Standby Letter of Credit
MWh	megawatt-hour	SCPPA	Southern California Public Power Authority
NBET	Nigerian Bulk Electricity Trading Ltd	SEB	State Electricity Board
NORAD	Norwegian Agency for Development Cooperation	Sida	Swedish International Development Cooperation Agency
Norfund	The Norwegian Investment Fund for Developing Countries	SOE	state-owned enterprise
NTPC	National Thermal Power Corporation	SPP	small power project
O&M	operations and maintenance	SPV	special-purpose vehicle
ODA	official development assistance	SSA	Sub-Saharan Africa
OECD	Organisation for Economic Co-operation and Development	STPPP	Short-Term Power Purchase Programme
Offtaker	Purchaser of power under a PSA with AGC	SEforALL	Sustainable Energy for All
OPIC	Overseas Private Investment Corporation	STEM	Short Term Energy Market
OPPI	Office for Promoting Private Power Investment	T&D	transmission and distribution
PDAM	Post-Day Ahead Market (now IDM)	TSO	Transmission System Operator
PFC	Power Finance Corporation	TV	Termination Value
PHCN	Power Holding Company of Nigeria	TWh	Terawatt hour
PPA	Power Purchase Agreement	VAT	value added tax
PRG	partial risk guarantee	USD	United States Dollar
PRI	political risk insurance	WB	World Bank
PPP	Public-Private Partnership	WBG	World Bank Group
PSA	Power Sale Agreement	ZAR	South African Rand
PTC	India Power Trading Corporation of India		
PIDA	Programme for Infrastructure Development in Africa		

**Africa GreenCo**

Ana Hajduka / Founder and CEO
Tel: +44(0) 7789 204 363
Email: ana.hajduka@africagreenco.com
www.africagreenco.com

Report design

Tareq Hossaine / Creative
Email: hossaine144@gmail.com
www.thpixel.com